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Coal Resources and Sulphur Emission Regulations
A Summary of Eight Eastern and Midwestern States

Versar, Inc.
Springfield, VA

Prepared for

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16. ABSTRACT

The report gives results of an analysis of coal resources, current coal use, and the effectiveness of SO2 control strategies for use by coal users, regulators, and administrators in future coal-related decisions. The report focuses on the eight major eastern and midwestern coal-producing states: Alabama, Illinois, Kentucky, Ohio, Pennsylvania, Virginia, West Virginia, and Indiana. Each state's analysis includes a general overview of the coal industry, an overview of coal properties, a description of major coal seams, an analysis of the quantity of coal available to meet various SO2 emission regulations, and information regarding the sulfur content of coals used by utilities in 1979. The report emphasizes physical coal cleaning and the use of low-sulfur coal as viable emission control strategies; flue gas desulfurization is discussed to a lesser extent. Data on coal resources, coal properties and washability, coal production, and deliveries to utilities were compiled from several sources and organized into computer data bases. The Coal Assessment Processor model was developed to operate on these data bases to determine the quantity of coal that would be available in each state to meet various SO2 emission regulations using one or a combination of alternative SO2 control technologies.

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Sulfur Oxides	Combustion	Washability	07B
Properties	Coal Handling		14G 15E
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Coal Resources and Sulphur Emission Regulations:

A Summary of Eight Eastern and Midwestern States

by

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CONVERSION FACTORS

ton = 0.907 metric tons

lb = 0.436 kg

Btu = 1055.6 Joule

Btu/lb = 2326 Joule/kg

in. = 2.54 cm

°C = 5/9 x (°F-32)

lb /in.^{2} = 0.07 kg/cm^2

lb $SO_2/10^6$ Btu = 430 ng SO_2/Joule

Foreword

Low sulfur coal and physically cleaned coal can be used to comply with many SO_2 emission regulations. Other more stringent regulations preclude the use of these coals without auxiliary SO_2 control methods such as Flue Gas Desulfurization (FGD).

The sulfur, ash content, and physical desulfurization potential of U.S. coals varies from seam to seam, from county to county and from region to region. Each coal is unique and a specific relationship exists between the coal properties, a given emission regulation and the ability of physical coal cleaning to produce a compliance coal. A single Federal SO_2 emission regulation will have different impacts on different coal producing states. Overly stringent regulations place serious economic constraints on the use of high sulfur coal resources. Unemployment and loss of capital investment will result. Overly lenient regulations may result in environmental damage. An understanding of the coal resources in each state is necessary to achieve a balance between environmental and economic priorities.

This report provides a concise summary of coal resources, and of the relationship between coal resources, SO_2 emission regulations, and coal cleaning. It is the culmination of more than ten years of cooperative research by EPA, DOE and private industry. It is a synthesis of work of our laboratory to understand the role which coal cleaning can play in controlling sulfur emissions from coal combustion. It is appropriate to acknowledge the special contributions of a number of organizations: the Department of Energy for the development of data bases on coal resources and coal washability; the Battelle Columbus Laboratories for development of the basic scheme and initial computer models for combining coal washability, coal resource, and coal cleaning technology information; Versar, Inc., for technical contributions and management of the final effort, and; Teknekron Research, Inc., for refinement of the coal assessment processor model and analysis of study results.

A final cautionary comment is needed. The results of this study are only as accurate as the underlying data bases and simplifying assumptions allow. We acknowledge the study's inherent limitations but believe that it presents a reasonable description of the coal resources in each state, and the potential to control SO_2 emissions by coal cleaning at the state level. More detailed questions concerning the efficiency of coal cleaning for controlling SO_2 emissions at a given plant require additional site and coal-specific information.

Frank T. Princiotta

Frank T. Princiotta, Director
Industrial Environmental Research Laboratory-RTP

ABSTRACT

Increasing demand for electric power and the national mandate to become less dependent on expensive, imported petroleum will result in the increased use of coal for power generation. Accompanying the changes in fuel mix will be revisions to environmental regulations and legislation affecting the use of coal. This report provides an analysis of coal resources, current coal use, and the effectiveness of SO_2 control strategies for use by coal users, regulators, and administrators in future coal-related decisions.

The report focuses on the eight major eastern and midwestern coal-producing states: Alabama, Illinois, Indiana, Kentucky, Ohio, Pennsylvania, Virginia, and West Virginia. Each state analysis includes a general overview of the coal industry, an overview of coal properties, a description of major coal seams, an analysis of the quantity of coal available to meet various SO_2 emissions regulations, and information regarding the sulfur content of coals used by utilities in 1979. The report focuses primarily on physical coal cleaning (PCC) and the use of low-sulfur coal as viable emission control strategies, with flue gas desulfurization (FGD) discussed to a lesser extent.

Data on coal resources, coal properties and washability, coal production, and deliveries to utilities were compiled from several sources and organized into computer data bases. The Coal Assessment Processor (CAP) model was developed to operate on these data bases to determine the quantity of coal that would be available in each state to meet various SO_2 emission regulations using one or a combination of alternative SO_2 control technologies. With this information, decision makers can examine the situation from state to state to identify the appropriate strategies for controlling SO_2 emissions from coal combustion

This report was prepared by Teknekron under Subcontract Agreement No. 553-1 and submitted in fulfillment of Contract No. 68-02-3136 by Versar, Inc., under the sponsorship of the U.S. Environmental Protection Agency. This report covers the period April 1979 to March 1981.

CONTENTS

	Page
FOREWORD	iii
ABSTRACT	iv
FIGURES	vii
TABLES	xi
ACKNOWLEDGEMENTS	xv
1. INTRODUCTION	1-1
2. CONCLUSIONS AND RECOMMENDATIONS	2-1
Section 2 References	2-6
3. METHODOLOGY	3-1
Section 3 References	3-9
4. STATE ANALYSES	4-1
4.1 Alabama	4-2
4.2 Illinois	4-10
4.3 Indiana	4-18
4.4 Kentucky	4-26
4.5 Ohio	4-38
4.6 Pennsylvania	4-46
4.7 Virginia	4-54
4.8 West Virginia	4-62
Section 4 References	4-74
APPENDIX A: Averaging Times	A-1

FIGURES

		Page
2-1	Projected SO_2 Emission Reduction by Control Strategy	2-5
2-2	Projected Cumulative SO_2 Emission Reduction since 1979 by Control Strategy	2-5
3-1	Comparison of CAP Model PCC I Results with Coal Preparation Plant Performance	3-4
3-2	Comparison of CAP Model PCC 2 Results with Coal Preparation Plant Performance	3-4
3-3	Percentage of Coal Reserves in Northern Appalachia Able to Meet Various Emission Limits Using Physical and Chemical Coal Cleaning (Total Coal Reserves = 1,734 Quads)	3-7
3-4	Percentage of Coal Reserves in Northern Appalachia Able to Meet Various Emission Limits Using Flue Gas Desulfurization, Fluidized Bed Combustion, and Coal Gasification for SO_2 Control (Total Coal Reserves = 1,734 Quads)	3-7
3-5	Levelized Physical Coal Cleaning Costs in 1978, Exclusive of Lost Coal Energy Cost, as a Function of Weight Loss	3-8
3-6	Comparison of CAP Model Levelized Coal Cleaning Cost with Thirteen Plant Design Costs (Including Cost of Lost-Coal Energy at $\$1/10^6$ Btu)	3-9
4.1-1	Alabama Coal Properties Fact Sheet	4-3
4.1-2	Alabama Coal Washability Data Sheet	4-4
4.1-3	Percentage of Projected 1985 Alabama Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization	4-6
4.1-4	Percentage of Projected 1985 Alabama Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.	4-7
4.2-1	Illinois Coal Properties Fact Sheet	4-11
4.2-2	Illinois Coal Washability Data Sheet	4-12

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FIGURES (Continued)

		Page
4.2-3	Percentage of Projected 1985 Illinois Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization	4-14
4.2-4	Percentage of Projected 1985 Illinois Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.	4-15
4.3-1	Indiana Coal Properties Fact Sheet	4-19
4.3-2	Indiana Coal Washability Data Sheet	4-20
4.3-3	Percentage of Projected 1985 Indiana Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization	4-22
4.3-4	Percentage of Projected 1985 Indiana Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.	4-23
4.4-1	Eastern Kentucky Coal Properties Fact Sheet	4-27
4.4-2	Western Kentucky Coal Properties Fact Sheet	4-28
4.4-3	Eastern Kentucky Coal Washability Data Sheet	4-29
4.4-4	Western Kentucky Coal Washability Data Sheet	4-30
4.4-5	Percentage of Projected 1985 Eastern Kentucky Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization	4-32
4.4-6	Percentage of Projected 1985 Eastern Kentucky Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.	4-33
4.4-7	Percentage of Projected 1985 Western Kentucky Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization	4-34

FIGURES (Continued)

		Page
4.4-8	Percentage of Projected 1985 Western Kentucky Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.	4-35
4.5-1	Ohio Coal Properties Fact Sheet	4-39
4.5-2	Ohio Coal Washability Data Sheet	4-40
4.5-3	Percentage of Projected 1985 Ohio Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization	4-42
4.5-4	Percentage of Projected 1985 Ohio Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.	4-43
4.6-1	Pennsylvania Coal Properties Fact Sheet	4-47
4.6-2	Pennsylvania Coal Washability Data Sheet	4-48
4.6-3	Percentage of Projected 1985 Pennsylvania Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization	4-50
4.6-4	Percentage of Projected 1985 Pennsylvania Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.	4-51
4.7-1	Virginia Coal Properties Fact Sheet	4-55
4.7-2	Virginia Coal Washability Data Sheet	4-56
4.7-3	Percentage of Projected 1985 Virginia Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization	4-58

FIGURES (Continued)

		Page
4.7-4	Percentage of Projected 1985 Virginia Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.	4-59
4.8-1	Northern West Virginia Coal Properties Fact Sheet	4-63
4.8-2	Southern West Virginia Coal Properties Fact Sheet	4-64
4.8-3	Northern West Virginia Coal Washability Data Sheet	4-65
4.8-4	Southern West Virginia Coal Washability Data Sheet	4-66
4.8-5	Percentage of Projected 1985 Northern West Virginia Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization	4-68
4.8-6	Percentage of Projected 1985 Northern West Virginia Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.	4-69
4.8-7	Percentage of Projected 1985 Southern West Virginia Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization	4-70
4.8-8	Percentage of Projected 1985 Southern West Virginia Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.	4-71

TABLES

		Page
2-1	Average Emission Potentials and Emission Reductions for Coal from Eight States	2-1
2-2	Current (1979) SO_2 Reduction Achieved by Cleaning Utility Coal from Eight States	2-2
2-3	Additional SO_2 Reduction That Could Have Been Achieved If All the 1979 Utility Coal from Eight States Had Been Cleaned	2-3
2-4	Emission Levels and Percentage SO_2 Reduction Achievable by One-Half of 1985 Planned Coal Production Using PCC 1	2-6
3-1	Typical Washability Data	3-3
3-2	Energy Consumed in the Production of Low- and Medium-Btu Gas	3-5
4.1-1	Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Alabama Coals Delivered to Utilities in 1979	4-7
4.1-2	Source State for Coal Used in Alabama Plants in 1979	4-8
4.1-3	Out-of-State Coal Use by Alabama Plants in 1979	4-8
4.1-4	States Receiving Alabama Coal Deliveries to Utility Plants in 1979	4-9
4.1-5	Alabama Utility Plants Receiving Alabama Coal Deliveries in 1979	4-9
4.2-1	Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Illinois Coals Delivered to Utilities in 1979	4-15
4.2-2	Source State for Coal Used in Illinois Plants in 1979	4-16
4.2-3	Out-of-State Coal Use by Illinois Plants in 1979	4-16
4.2-4	States Receiving Illinois Coal Deliveries to Utility Plants in 1979	4-17
4.2-5	Illinois Utility Plants Receiving Illinois Coal Deliveries in 1979	4-17

TABLES (Continued)

		Page
4.3-1	Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Indiana Coals Delivered to Utilities in 1979	4-23
4.3-2	Source State for Coal Used in Indiana Plants in 1979	4-24
4.3-3	Out-of-State Coal Use by Indiana Plants in 1979	4-24
4.3-4	States Receiving Indicna Coal Deliveries to Utility Plants in 1979	4-25
4.3-5	Indiana Utility Plants Receiving Indiana Coal Deliveries in 1979	4-25
4.4-1	Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Eastern Kentucky Coals Delivered to Utilities in 1979	4-33
4.4-2	Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Western Kentucky Coals Delivered to Utilities in 1979	4-35
4.4-3	Source State for Coal Used in Kentucky Plants in 1979	4-36
4.4-4	Out-of-State Coal Use by Kentucky Plants in 1979	4-36
4.4-5	States Receiving Kentucky Coal Deliveries to Utility Plants in 1979	4-37
4.4-6	Kentucky Utility Plants Receiving Kentucky Coal Deliveries in 1979	4-37
4.5-1	Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Ohio Coals Delivered to Utilities in 1979	4-43
4.5-2	Source State for Coal Used in Ohio Plants	4-44
4.5-3	Out-of-State Coal Use by Ohio Plants	4-44
4.5-4	States Receiving Ohio Coal Deliveried to Utility Plants in 1979	4-45

TABLES (Continued)

		Page
4.5-5	Ohio Utility Plants Receiving Ohio Coal Deliveries in 1979	4-45
4.6-1	Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Pennsylvania Coals Delivered to Utilities in 1979	4-51
4.6-2	Source State for Coal Used in Pennsylvania Plants in 1979	4-52
4.6-3	Out-of-State Coal Use by Pennsylvania Plants in 1979	4-52
4.6-4	States Receiving Pennsylvania Coal Deliveries to Utility Plants in 1979	4-53
4.6-5	Pennsylvania Utility Plants Receiving Pennsylvania Coal Deliveries in 1979	4-53
4.7-1	Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Virginia Coals Delivered to Utilities in 1979	4-59
4.7-2	Source State for Coal Used in Virginia Plants in 1979	4-60
4.7-3	Out-of-State Coal Use by Virginia Plants in 1979	4-60
4.7-4	States Receiving Virginia Coal Deliveries in Utility Plants in 1979	4-61
4.7-5	Virginia Utility Plants Receiving Virginia Coal Deliveries in 1979	4-61
4.8-1	Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Northern West Virginia Coals Delivered to Utilities in 1979	4-69
4.8-2	Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Southern West Virginia Coals Delivered to Utilities in 1979	4-71
4.8-3	Source State for Coal Used in West Virginia Plants in 1979	4-72

TABLES (Continued)

		Page
4.8-4	Out-of-State Coal Use by West Virginia Plants in 1979	4-72
4.8-5	States Receiving West Virginia Coal Deliveries to Utility Plants in 1979	4-73
4.8-6	West Virginia Utility Plants Receiving West Virginia Coal Deliveries in 1979	4-73
A-1	Typical Coal Sulfur RSD Values Reported by EPA as a Function of Coal Sample Size	A-2
A-2	Example Normal Variates and Implications of Confidence Level on Expected SO_2 Violations	A-3
A-3	Mean Coal SO_2 Contents Equivalent to Selected Short-Term Emission Limits for Various Values of Coal Sulfur RSD	A-3

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1. INTRODUCTION

BACKGROUND

In the next several years in the United States, an increasing amount of coal will be used for power generation. This will be due both to an increased demand for electric power and to the national mandate to become less dependent on expensive, imported petroleum. Accompanying the changes in fuel mix will be revisions to environmental regulations and legislation affecting the use of coal.

AIR POLLUTION REGULATIONS

The Clean Air Act of 1970 (P.L. 91-604) and its Amendments of 1977 (P.L. 95-95) provide authority for the U.S. Environmental Protection Agency (EPA) to control the discharge of air pollutants into the atmosphere. The Act requires EPA to coordinate, develop, and implement regulations designed to limit the quantity of pollutants in the ambient air and to control pollutant emissions to the atmosphere from stationary and mobile sources. As such, the Act contains several regulatory and enforcement actions for control of emissions from stationary sources using coal. Actions include: (1) creating National Ambient Air Quality Standards (NAAQS) and implementing State Implementation Plans (SIP) to meet these standards, (2) promulgating New Source Performance Standards (NSPS) on the federal level, and (3) establishing Prevention of Significant Deterioration (PSD) regulations on the national level and nonattainment area designations on the state level.

National Ambient Air Quality Standards and State Implementation Plans

Under Section 109 of the Act, NAAQS have been set by EPA on sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide, photochemical oxidants, hydrocarbons, and lead. To implement these standards, each state must develop a detailed plan for attaining and maintaining the NAAQS in all regions of the state. These State Implementation Plans, which must be approved by EPA (per Section 110 of the Act), include emission limits, timetables for compliance, and enforcement programs. The primary source of sulfur dioxide that affects ambient air quality is the combustion of solid and liquid fuels in stationary sources. Therefore pre- and post-combustion control of sulfur in power plants is a major tool in each SIP for meeting the NAAQS for sulfur dioxide.

SIP limits for SO_2 are often set by the state at a level that will not discourage the use of local coal. Furthermore, lower limits are usually set for units located in urban areas than for units located in rural parts of the state. For example, in Pennsylvania the SIP limit for many units located in the rural areas and near major coal fields is 3.3 lb $SO_2/10^6$ Btu, while the SIP limit for units located near urban areas is in the 0.6 to 0.7 lb $SO_2/10^6$ Btu range.

New Source Performance Standards

Section 111 of the Act requires EPA to issue New Source Performance Standards for emissions from new and modified sources that contribute significantly to air pollution and endanger the public health and welfare. The standards must reflect the best degree of control and take cost, energy, and non-air related environmental impacts into account.

The Amendments of 1977 specifically mention the need to revise and/or develop NSPS for fossil-fuel-fired boilers. The original NSPS, which is applicable to large coal-fired boilers (greater than 250 million Btu/hr heat input) built or modified between 1972 and 1979, specifies an emission limit of 1.2 lb $SO_2/10^6$ Btu.

The large coal-fired boiler NSPS was revised in 1978 to reflect "a degree of emission limitation and percentage reduction achievable through application of the best technological system of emission

reduction." The revised NSPS specified a maximum emission limit of 1.2 lb $SO_2/10^6$ Btu, combined with 90 percent sulfur dioxide removal. A floor of 0.6 lb SO_2/Btu was set along with a minimum 70 percent reduction in sulfur dioxide. Emission limits are average levels not to be exceeded during a 30-day (running) average. Sulfur reduction credits for coal cleaning are given on the basis of a 3-month average for sulfur removed at the preparation plant.

ISSUES

Regulatory considerations will include a growing realization that accelerated coal use may make it more difficult to meet State Implementation Plans (SIPs), to meet Prevention of Significant Deterioration (PSD) requirements while still permitting growth, to find sufficient offsets in nonattainment areas, and to find cost-effective ways to control emissions from small boilers. Furthermore, there is an emerging awareness of the acid rain/acid deposition problem and of the fact that fuel sulfur variability and temporal variations in the efficiency of flue gas scrubbers are significant determinants of whether any given source will exceed specified emission regulations.

COAL RESOURCE ASSESSMENT

To respond to these considerations in their future coal-related decisions, coal users, regulators, and administrators will have to be armed with extensive information on coal resources, current coal use, sulfur dioxide (SO_2) control technologies, and alternative SO_2 emission regulatory strategies. This document, accordingly, supplies information on coal resources, current coal use, and the effectiveness and costs of SO_2 control technologies for the eight major eastern and midwestern coal-producing states: Alabama, Illinois, Indiana, Kentucky, Ohio, Pennsylvania, Virginia, and West Virginia. Each state analysis includes a general overview of the coal industry, an overview of coal properties, a description of major coal seams, an analysis of the quantity of coal available to meet various SO_2 emission regulations, and information regarding the sulfur content of coals used by utilities in 1979. The report focuses primarily on physical coal cleaning (PCC) and the use of low-sulfur coal as viable emission control strategies, with flue gas desulfurization (FGD) discussed to a lesser extent.

APPROACH

Data on coal resources, coal properties and washability, coal production, and deliveries to utilities were compiled from several sources and organized into computer data bases. The Coal Assessment Processor (CAP) model was developed to operate on these data bases to determine the quantity of coal that would be available in each state to meet various SO_2 emission regulations using one or a combination of alternative SO_2 control technologies. With this information, decision makers can examine the situation from state to state to identify the appropriate strategies for ensuring compliance with SO_2 emission regulations.

The report is organized into four sections: Introduction, Conclusions and Recommendations, Methodology, and State Analyses.

2. CONCLUSIONS AND RECOMMENDATIONS

Where Physical Coal Cleaning is Most Effective

Coals that are naturally low in sulfur or whose sulfur content has been reduced by the use of physical coal cleaning can be used to comply with the State Implementation Plan (SIP) and 1971 New Source Performance Standard (NSPS) regulations governing sulfur dioxide emissions from coal-fired utility boilers. Also, in some cases, PCC plus FGD may be a cost-effective SO_2 control strategy for emission regulations requiring large percentage SO_2 reductions that cannot be achieved by PCC alone. Physical coal cleaning (PCC) is the generic name for a technological process that removes ash and pyritic sulfur from coal. With regard to sulfur removal, PCC is most effective when used with coal whose pyritic sulfur content is high. In the United States, coals of this type are mined in northern Appalachia and the eastern Midwest. The desulfurization potential of PCC is determined by laboratory washability tests on specific coal samples. Table 2-1 shows, for various coal-producing states, the relationship between the average emission potential of the coal and the percentage by which SO_2 emission can be reduced using a moderate level of coal cleaning. Although the data in the table represent laboratory washability results for just a limited number of samples, they are useful in illustrating the relationship between coal characteristics and washability. Furthermore, they indicate the kind of coal typically found in each state.

Table 2-1

Average Emission Potentials and Emission Reductions for Coal from Eight States

Region and State	Number of Washability Samples	Average Emission Potential (lb $SO_2/10^6$ Btu)	Average Emission Reduction Using PCC 1* (%)
Northern Appalachia			
Pennsylvania	170	4.0	33.2
Ohio	90	5.8	25.9
Northern West Virginia	30	4.9	28.6
Southern Appalachia			
Southern West Virginia	16	1.4	10.1
Virginia	8	1.1	7.6
Eastern Kentucky	13	2.3	15.9
Eastern Midwest			
Western Kentucky	37	6.6	31.5
Indiana	21	5.9	26.4
Illinois	40	6.6	29.3
Alabama			
Alabama	10	2.0	10.8

* PCC 1 is equivalent to coal crushed to 1 1/2 inch top size and separated at 1.6 specific gravity.

For example, western Kentucky coal has a high average emission potential of 6.6 pounds of SO_2 per million Btu, but moderate cleaning of the coal can provide a 31.5 percent reduction in SO_2 emissions. Virginia coal illustrates the other extreme: its typical emission potential is low (1.1 lb $SO_2/10^6$ Btu), and

the percentage of emission reduction also is low (7.6 percent). Pennsylvania shows a slightly different pattern – a moderate emission potential of 4.0 lb $SO_2/10^6$ Btu and a high average percentage emission reduction of 33.2 percent – which is partially explained by the relatively high pyritic sulfur content compared with total sulfur content.

Table 2-2 summarizes the current extent to which electric utilities are using coal cleaning for ash and SO_2 reduction. The data are from the 1979 deliveries-to-utilities data base combined with the coal washability data base (the data bases are described in Section 3). The deliveries-to-utilities data base specifies the SO_2 content of the as-delivered coal and the quantity of coal cleaned prior to delivery. These specifications were converted to the as-mined quantities and SO_2 contents presented in Table 2-2 by assuming that the washability characteristics of the coals washed prior to delivery were the same as those of the coals that were not washed prior to delivery. For example, as shown later in Table 4.1-1, a 21 percent SO_2 reduction can be achieved by washing Alabama coals. Therefore, it was assumed that the washed Alabama coals delivered to utilities had had their SO_2 content reduced by 21 percent in the washing process, and that, accordingly, the as-mined SO_2 content was equal to the as-delivered SO_2 content divided by 0.79 (i.e., 1-0.21). Coal weight prior to washing was calculated in a similar manner, to determine the percentage of utility coal cleaned in 1979.

Table 2-2

Current (1979) SO_2 Reduction Achieved by Cleaning Utility Coal from Eight States

Region and State in Which Coal Was Mined	Coal Delivered to Utilities in 1979 (10^3 Tons)	Utility Coal Cleaned in 1979 (Percent)	SO_2 Content of Coal		Average SO_2 Reduction by Coal Cleaning in 1979 (Percent)
			As-Mined (10^3 Tons)	As Delivered (10^3 tons)	
Northern Appalachia					
Pennsylvania	47,400	30	2,100	1,860	12
Ohio	38,300	11	2,750	2,670	3
Northern West Virginia	31,300	23	1,760	1,690	4
Southern Appalachia					
Southern West Virginia	17,500	9	300	290	1
Virginia	13,400	7	280	270	1
Eastern Kentucky	68,600	22	1,630	1,570	4
Eastern Midwest					
Western Kentucky	38,100	34	2,880	2,600	10
Indiana	25,300	52	1,620	1,410	13
Illinois	49,500	72	3,570	2,780	22
Alabama					
Alabama	14,600	32	460	440	5
EIGHT-STATE TOTAL	344,000	33	17,340	15,570	10

Table 2-2 shows, for example, that over one-half of the coal from Indiana and Illinois and about one-third of the coal from Pennsylvania, western Kentucky, and Alabama were cleaned prior to delivery to utilities in 1979, and that this cleaning resulted in significant SO_2 reductions. On the other hand, only small percentages of the coal from Ohio, southern West Virginia, and Virginia were cleaned prior to utility use in 1979.

The SO_2 reduction that could have been achieved if all coal delivered to utilities in 1979 had been cleaned at 1 1/2 inch top size and 1.6 specific gravity (i.e., moderate cleaning) is summarized in Table 2-3.

Table 2-3

Additional SO_2 Reduction That Could Have Been Achieved If All the 1979 Utility Coal from Eight States Had Been Cleaned

Region and State in Which Coal Was Mined	Additional SO_2 Reduction* by Washing All Coal		Levelized Cost of Cleaning the Additional Coals		Cost-Effectiveness of Coal Cleaning ($/Ton SO_2 Removed)
	(10^3 Tons)	(Percent)	($/Ton**)	(Mills/kWh***)	
Northern Appalachia					
Pennsylvania	470	25	9.10	4.0	670
Ohio	740	28	9.30	4.4	430
Northern West Virginia	280	16	8.00	3.5	720
Southern Appalachia					
Southern West Virginia	30	11	7.90	3.4	4,100
Virginia	30	10	8.30	3.5	3,700
Eastern Kentucky	260	16	10.00	4.4	2,200
Eastern Midwest					
Western Kentucky	530	21	6.50	3.1	310
Indiana	180	13	4.60	2.2	310
Illinois	230	8	6.60	3.3	430
Alabama					
Alabama	70	17	8.60	3.8	1,200
EIGHT-STATE TOTAL	2,850	18	8.40	3.8	710

* Over current practice (see Table 2-2).

** Of raw coal.

*** For a generating unit with a heat rate of 10,000 Btu/kWh.

This table illustrates, for example, that about 1.7 million more tons of SO_2 could have been removed in 1979 by cleaning all the utility coal from Pennsylvania, Ohio, and western Kentucky, and that moderate SO_2 reductions could have been achieved by washing other northern Appalachian and eastern Midwest coals.

Typically, a coal user will purchase washed coal if he perceives an economic advantage to doing so. As shown in Table 2-3, the estimated levelized costs of cleaning utility coal range from $5 to $10 per ton. The weighted average delivered cost of raw coal from the eight states shown in Table 2-3 amounted to about $30 per ton ($60 per ton levelized) in 1979. Cleaning all the coals would have increased this cost by only 10-20 percent – a low price to pay compared with that of other SO_2 control strategies. Another measure of the cost of pollution control is the cost-effectiveness of the process, which is calculated as the cost per ton of SO_2 removed. The average cost-effectiveness of PCC for utility coal in each state in 1979 is shown in the final column of Table 2-3. Cost-effectiveness is partially a function of the washability of the coal. Clearly, PCC is more cost-effective for western Kentucky coals than for southern West Virginia coals ($310/ton versus $4,100/ton of SO_2 removed). Fortunately, coal cleaning is most cost-effective with those coals that have the greatest potential SO_2 reduction. For example, the costs of SO_2 reduction for eastern Kentucky coals may range from $460/ton of SO_2 for high-sulfur coals to more than $3,000/ton of SO_2 for low-sulfur coals.

Certain benefits of coal cleaning can reduce the boiler operator's overall costs to the point of offsetting some, or even all, of his coal-cleaning costs. For example, burning cleaned coal can reduce boiler maintenance costs and increase boiler reliability, especially if the boiler is currently experiencing ash-fouling problems. Other benefits include reduced costs for coal transportation, coal handling, ash handling, and stack gas cleaning. Furthermore, PCC processes reduce the variability of a coal's sulfur content, making it easier to meet SO_2 emission regulations. These factors contribute to the economic advantage of burning cleaned coal.

Impact of Physical Coal Cleaning on National SO_2 Emissions

The cost of pollution control is a function of emission regulations, coal properties, and boiler characteristics. Over the next 20 years, most utility boilers in the United States will still be governed by SIP regulations or by the 1.2 $lb/10^6$ Btu New Source Performance Standard (NSPS). The NSPS emission ceiling often encourages the use of either low-sulfur compliance coal or an FGD system. However, in the case of SIP regulations, the SO_2 limits applicable to many of the SIP-governed units are high enough to allow the use of higher-sulfur local coals, cleaned or uncleaned.

In a recent acid-rain-mitigation analysis conducted for EPA and DOE,[1] the least-cost SO_2 compliance strategy was determined for each existing and future coal-fired electric generating unit in the United States, assuming various SIP emission-regulation scenarios. In the base-case SIP compliance scenario, units currently in compliance with their SIP or NSPS SO_2 emission regulations were assumed to continue to use the same coal sources and washing practices used in 1979. Units not currently in compliance were assumed to switch to a low-sulfur coal, physically clean coals from the same sources used in 1979, or build an FGD system, whichever proved cheapest. For this analysis it was assumed that a unit could use an FGD system with the 1979 coal as delivered, with the 1979 coal after physical cleaning, or with a local high-sulfur coal. The use of PCC for coals other than those received in 1979 was not considered in this analysis.

The projected SO_2 emission reduction (i.e., the difference between 1979 uncontrolled and controlled emissions) through the year 2000 is summarized in Figure 2-1 for the least-cost control strategies selected for each generating unit. Physical coal cleaning of their 1979 deliveries was selected by 27 SIP and NSPS units, while switching to low-sulfur coal was selected by 114 units. If this analysis had included the option of using PCC on coals other than those received in 1979, many of the SIP and NSPS units selecting low-sulfur coal would have used physically cleaned alternative coals. Therefore, the SO_2 emission reduction for PCC and coal switching are combined in Figure 2-1. Physical coal cleaning currently reduces SO_2 emissions by about 1.7 million tons per year; this total was added to the SO_2 reduction projected to be achieved by PCC and coal switching (phased in over a 5-year period) to produce a maximum reduction of about 2.5 million tons per year in 1985. FGD systems were chosen as the least-cost SO_2 control strategy for 63 SIP and 44 NSPS units and, as shown in the figure, were found to reduce SO_2 emissions by about 2.1 million tons per year in 1985. The use of FGD systems by new units governed by the 1978 NSPS is responsible for the increase shown in FGD SO_2 reductions after 1985.

Also shown in Figure 2-1 is the SO_2 reduction that could be achieved if all coals delivered to utilities in 1979 were physically cleaned. If this strategy for additional SO_2 reduction were phased in over a 10-year period, about 5 million tons of SO_2 per year would be removed by PCC in 1990. SO_2 reduction from SIP and NSPS units using physical coal cleaning decreases after 1990 due to the projected retirement of these units. If the use of physically cleaned coals in units governed by the 1978 NSPS had been considered in this analysis, SO_2 reduction from PCC probably would not show a decrease after 1990.

Figure 2-2 shows the projected cumulative SO_2 reduction achievable between 1979 and 2000 by each of the SO_2 control strategies. Coal switching plus PCC and FGD each will achieve a cumulative removal of about 24 million tons by 1989; and if all SIP and NSPS coals were washed, FGD and coal switching plus PCC each would achieve a cumulative SO_2 reduction of about 60 million tons in 1994.

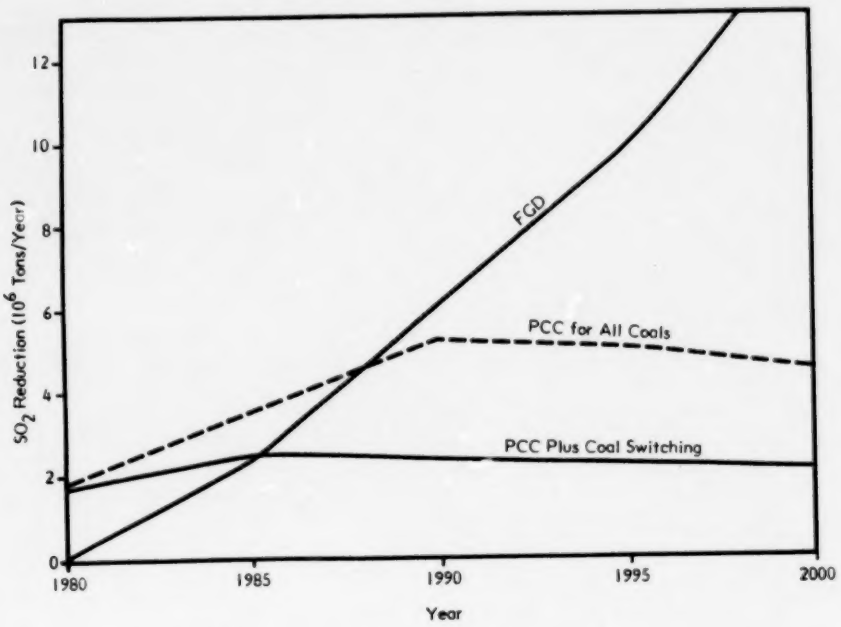


Figure 2-1. **Projected SO_2 Emission Reduction by Control Strategy.**

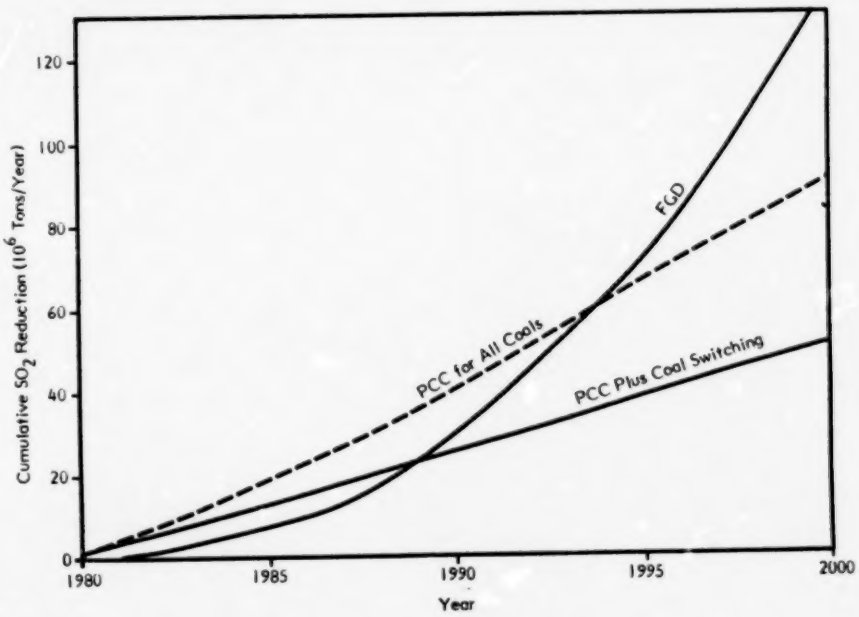


Figure 2-2. **Projected Cumulative SO_2 Emission Reduction since 1979 by Control Strategy.**

SO_2 Emission Regulations That Can Be Met By Physical Coal Cleaning

PCC can reduce the sulfur content of many coals by 20 to 30 percent. Many coals, however, are so high in sulfur that even a 20 to 30 percent reduction cannot bring them into compliance with current SIP regulations. Table 2-4 shows the average SO_2 reduction and emission levels that can be met by about one-half of the projected 1985 coal production in each state by coal cleaning at 1-1/2 inches and 1.6 specific gravity (PCC I).

Table 2-4

Emission Levels and Percentage SO_2 Reduction Achievable by One-Half of 1985 Planned Coal Production Using PCC I

Region and State in Which Coal Will Be Produced	SO_2 Emission Level (lb $SO_2/10^6$ Btu)	SO_2 Emission Reduction (Percent)
Northern Appalachia		
Pennsylvania	2	33
Ohio	4	22
Northern West Virginia	3	20
Southern Appalachia		
Southern West Virginia	1	10
Virginia	1	5
Eastern Kentucky	1	16
Eastern Midwest		
Western Kentucky	4-5	24
Indiana	4	7
Illinois	4-5	24
Alabama		
Alabama	1-2	9

These figures show that physical coal cleaning will allow about half of the projected 1985 coal production from Pennsylvania, southern West Virginia, Virginia, eastern Kentucky, and Alabama to meet SO_2 emission levels below 2.0 lb $SO_2/10^6$ Btu and about half of the projected 1985 production from Pennsylvania, Ohio, northern West Virginia, western Kentucky, and Illinois to achieve SO_2 reductions of 20 percent or more.

In considering changes in air pollution emission regulations, it is important to keep in mind the local coal market and its impact on local employment. Each state analysis in this report includes employment and production data for 1977. The labor requirements in the different states vary depending primarily on coal mining methods. A measure of the relative labor intensity of mining for each state can be determined by calculating the number of workers per ton of coal mined. Coal mining in states such as West Virginia, Alabama, Pennsylvania, and Virginia is more labor intensive (more workers per ton of coal produced) because of the heavy reliance on underground mining. Accordingly, regulations affecting coal production could affect workers in these states more than those in other, less labor intensive, areas.

References:

1. Teknekron Research, Inc., Acid Rain Mitigation Study: Emission Control Strategies and Costs, R-003-EPA-81, Draft Report Prepared for U.S. Environmental Protection Agency, Washington, D.C., and U.S. Department of Energy, Argonne National Laboratory, Argonne, Illinois (Berkeley, Calif., February 1981).

3. METHODOLOGY

Introduction

Each state analysis in Section 4 is organized to provide:

- A general overview of the state's coal industry, including the location of coal fields, coal production and employment for major counties, and current coal washing practices
- An overview of the properties of the coal in the state, with an emphasis on coal sulfur content
- A description of the major coal seams in the state
- A discussion of the quantity of coal able to meet various SO_2 emissions ceilings, floors, and percentage removal standards using PCC and FGD
- A presentation of the extent of coal movement between states, and a review of the coal-blending stategies used by the state's major utility plants to comply with the SIP SO_2 standard

The information was compiled from a number of existing sources (as documented in the references) and from simulations using the Coal Assessment Processor (CAP) model. The CAP model was developed under the EPA Coal Cleaning Program to determine the quantity of coal available in the United States to meet various SO_2 emission regulations. Five coal data bases and a washability data base were compiled to interface with the model. The coal data bases include information on reserves, 1976 production, 1985 planned production, and deliveries to utilities from September 1977 to September 1978 and from January to December 1979. The washability data include experimental sulfur and ash reductions for over 500 coals. The SO_2 control technologies simulated by the CAP model include various PCC and chemical coal cleaning (CCC) processes, FGD, fluidized bed combustion (FBC), low-Btu gasification, medium-Btu gasification, and PCC + FGD. Performance models for each of these control technologies determine potential SO_2 reduction and energy penalties. Only PCC and FGD are considered in this report. The coal data bases and the CAP model's treatment of SO_2 control technologies, SO_2 emission limits, and PCC cost simulations are discussed in detail below.

COAL DATA BASES

Reserves Data Base

The coal reserves data base contains 52,986 records, each specifying a given coal's location, quantity, and properties. Coal quantities were derived from 3,167 resource records representing the demonstrated coal reserve base as summarized in Bureau of Mines (BOM) Reports IC 8680 and IC 8693.[1,2] Coal properties and locations from nearly 269,000 sample analyses recorded in the "historical coals file" archived by the BOM in Denver, Colorado, were matched geographically with the 3,167 resource records to produce the 52,986-record reserves data base. Coal properties currently specified in the reserves data base include heating value, sulfur content, and ash content (on a moisture-free basis) and moisture content. Sulfur content is divided into pyritic and organic sulfur in proportion to their ratio in the washability data base. Other coal properties available from the BOM "historical coal file" for addition to the reserves data base include: (1) proximate analysis; (2) ultimate analysis; (3) ash softening temperature; (4) free swelling index; (5) Hardgrove grindability index; and (6) preparation code (i.e., washed or not washed).

Efforts are currently under way to add trace element information to the data base. USCHEM, the trace element data base of the U.S. Geological Survey (USGS) National Coal Resources Data System, has recently been acquired. This data base contains information on the quantity of 61 trace elements in 3,475 of the 4,043 coal samples in the USGS data system. Other sources of trace element information being pursued include Pennsylvania State University records and various state geologic surveys.

1976 Production Data Base

The data base on 1976 production contains 3,074 records, each specifying a given coal's location, quantity, and properties. Information on the location and quantity of coal produced in 1976 was obtained primarily from annual state coal-production reports, a 1979 Ohio River Basin Energy Study (ORBES) report,[3] and various Keystone manuals.[4,5] In many cases these sources listed high, mean, and low values for coal heating value and moisture, ash, and sulfur content. This information was used in assigning coal properties from the BOM "historical coals file" to the 1976 production data base. As shown by the histograms presented in Section 4, the coal sulfur contents specified in the 1976 production data base differ in many cases from the coal sulfur contents specified in the reserves data base. These differences reflect the selective mining of each state's coal reserves in 1976.

1985 Production Data Base

The data base on production planned for 1985 was developed from individual mine-expansion plans reported by the National Coal Association (NCA)[6] and the Department of Energy's Western Coal Development Monitoring System (WCD).[7] The NCA data were combined with the 1976 production data for the eastern states, and the WCD data were combined with the 1976 producton data for the western states, to form the 4,328-record data base on projected 1985 production. Like the reserves and 1976 production data bases, this data base uses BOM "historical coals file" coal properties. The 1985 coal sulfur content histograms are similar to the 1976 histograms, and any differences are due to planned shifts in coal production from various mines and seams.

Deliveries-to-Utilities Data Base: 1977/1978 and 1979

The deliveries-to-utilities data base includes information on the quantity, cost, and properties (sulfur, ash, heating value) of all coals delivered to utilities from September 1977 to September 1978 and from January through December 1979, as reported to the Department of Energy on EIA Form 423. The Form 423 data for September 1977 to September 1978 were obtained from NCA, while the data for January through December 1979 were obtained from Coal Outlook (a weekly document issued by Pasha Publications). Unlike the other data bases, this one does not take coal properties from the BOM "historical coals file." In addition to coal quantities and properties, this data base includes information, obtained by Versar, Inc., on which coals were physically cleaned before delivery in 1979. This feature allows the CAP model to clean only those coals not already cleaned prior to delivery.

Coal Washability

The coal washability data base contains information on the composition and washability characteristics of 587 coal samples as reported by the Bureau of Mines in report RI 8118[8] and later unpublished supplements. The data base specifies the location of samples by state, county, and coalbed. For each sample, the results of laboratory float-sink testing are included for samples crushed to pass 1.5 inch, 3/8 inch, and 14-mesh screens. The following information is included for the total sample and for products floating at 1.3, 1.4, 1.6, and sometimes 1.9 specific gravity: weight recovery, Btu recovery, heating value, pyritic sulfur percentage, total sulfur percentage, ash percentage, and pounds of potential SO_2 per million Btu. Typical washability data are shown in Table 3-1.

In the CAP model, each data-base coal at the county-seam level is assigned the washability characteristics of one or more of the 587 coal samples. Washability assignments are made on a geographical basis in the following order of priority: (1) county bed, (2) state bed, (3) state county, (4) out-of-state bed, (5) closest out-of-state sample. Coals from Appalachia (Alabama, Georgia, eastern Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) and from the eastern Midwest (Illinois, Indiana, and western Kentucky) are represented by 380 and 98 washability samples, respectively, and in most cases county-bed or state-bed matching is possible. For the remaining coal regions, represented by only 109 washability samples, matching is often more tenuous.

Table 3-1. Typical Washability Data

STATE: OHIO
COUNTY: COSHOCTON

COALBED: MIDDLE KITTANNING
RAW COAL MOISTURE: 4.1 %

CUMULATIVE WASHABILITY DATA

SAMPLE CRUSHED TO PASS 1-1/2 INCHES

PRODUCT	RECOVERY,% WEIGHT	RECOVERY,% BTU	BTU/LB	ASH,%	SULFUR,% PYRITIC	SULFUR,% TOTAL	LB SO2/M BTU
FLOAT-1.30	50.0	56.6	13940	2.3	.61	2.28	3.3
FLOAT-1.40	76.9	85.7	13722	3.8	1.20	2.97	4.3
FLOAT-1.60	83.7	92.4	13591	4.7	1.55	3.35	4.9
TOTAL	100.0	100.0	12314	13.5	4.51	6.36	10.3

SAMPLE CRUSHED TO PASS 3/8 INCH

PRODUCT	RECOVERY,% WEIGHT	RECOVERY,% BTU	BTU/LB	ASH,%	SULFUR,% PYRITIC	SULFUR,% TOTAL	LB SO2/M BTU
FLOAT-1.30	51.9	58.5	13969	2.1	.67	2.19	3.1
FLOAT-1.40	75.1	83.7	13809	3.2	.95	2.75	4.0
FLOAT-1.60	83.7	92.2	13649	4.3	1.37	3.20	4.7
TOTAL	100.0	100.0	12386	13.0	4.34	6.17	10.0

SAMPLE CRUSHED TO PASS 14 MESH

PRODUCT	RECOVERY,% WEIGHT	RECOVERY,% BTU	BTU/LB	ASH,%	SULFUR,% PYRITIC	SULFUR,% TOTAL	LB SO2/M BTU
FLOAT-1.30	52.2	59.8	13998	1.9	.60	2.13	3.0
FLOAT-1.40	71.4	81.1	13882	2.7	.73	2.54	3.7
FLOAT-1.60	83.3	93.1	13664	4.2	1.12	2.90	4.2
TOTAL	100.0	100.0	12227	14.1	4.50	6.39	10.5

Source: Reference 8.

SO_2 EMISSION CONTROL TECHNOLOGIES

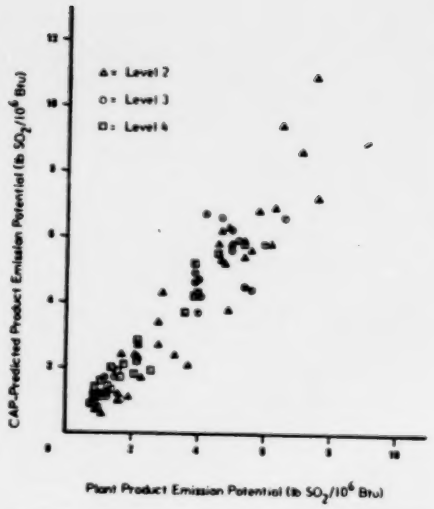
Physical Coal Cleaning

Commercial PCC processes are separated into five different levels:

- Level 1: Removes mine debris and noncombustible impurities. Unit operations include crushing and particle sizing.
- Level 2: Coal is crushed and classified. Only the course coal (+3/8 or +1/4 inch) is cleaned.
- Level 3: Coal is crushed and classified. Coarse and intermediate (1/4 inch x 28 mesh) size fractions are cleaned in separate circuits. Fine coal (28 mesh x 0) is dewatered and either shipped with the cleaned coal or discarded.
- Level 4: Coal is crushed and classified. Coarse, intermediate, and fine coal size fractions are cleaned in separate circuits.
- Level 5: Similar to Level 4 except that separations are achieved at two or more stages. The product consists of premium-quality clean coal and middling coal.

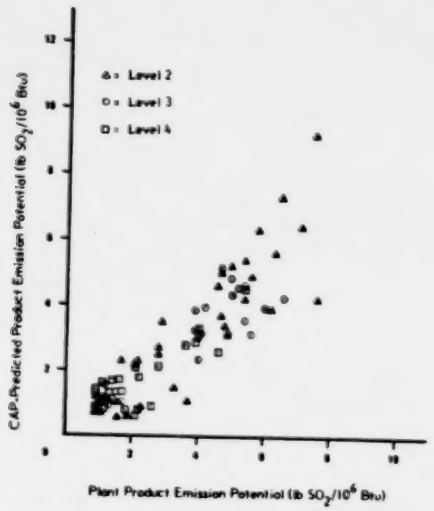
The PCC processes that can be simulated by the CAP model include any combination of top size (i.e., 1.5 inch, 3/8 inch, 14 mesh) and specific gravity (i.e., 1.3, 1.4, 1.6). For these state analyses, only two combinations were chosen: 1-1/2 inch top size, 1.6 specific gravity; and 3/8 inch top size, 1.3 specific gravity. The first combination is called PCC I; and the second, PCC II. The PCC I simulation best corresponds to the Level 3 commercial process. To verify the CAP model's coal-cleaning simulations, a comparison was made of the CAP-predicted characteristics of cleaned coals and the characteristics of actual cleaning-plant products. Data on 85 actual preparation-plant feed coals were input to the CAP model. The model predicted their sulfur and Btu contents after cleaning, using both coal-cleaning

algorithms (i.e., PCC I and PCC II). The cleaned-coal properties were determined by multiplying the uncleaned coal properties from the coal data base by the ratio of the corresponding cleaned to uncleaned coal properties in the washability data base. The predictions were compared with the sulfur and Btu contents of the actual cleaning-plant products. Results were characterized in terms of SO_2 emission potential (lb $SO_2/10^6$ Btu). Linear regression analyses were conducted with the data grouped according to commercial cleaning levels (2, 3, and 4) and with all levels combined. The results, presented in Figures 3-1 and 3-2, show significant agreement between the predicted results of cleaning and the actual plant products. Linear regression equations and correlation coefficients derived from the data analyses show that CAP-based predictions exhibit good accuracy. The equations also indicate that the CAP-predicted PCC I products tend to have a higher SO_2 emission potential (are less "clean") than the plant products. Conversely, the CAP-predicted PCC 2 products have a lower SO_2 emission potential (are more "clean") than the plant products.


Δ = Level 2
○ = Level 3
□ = Level 4
CAP-Predicted Product Emission Potential (lb SO2/10^6 Btu)
Plant Product Emission Potential (lb SO2/10^6 Btu)

Cleaning Level	Regression Equation	Correlation Coefficient (r)
2	Y = 1.28X - 0.71	0.94
3	Y = 1.07X + 0.02	0.92
4	Y = 1.10X + 0.04	0.97
All	Y = 1.17X - 0.21	0.94

Figure 3-1. Comparison of CAP Model PCC I Results with Coal Preparation Plant Performance


Δ = Level 2
○ = Level 3
□ = Level 4
CAP-Predicted Product Emission Potential (lb SO2/10^6 Btu)
Plant Product Emission Potential (lb SO2/10^6 Btu)

Cleaning Level	Regression Equation	Correlation Coefficient (r)
2	Y = 0.96X - 0.40	0.87
3	Y = 0.72X + 0.23	0.90
4	Y = 0.65X + 0.31	0.86
All	Y = 0.85X - 0.08	0.89

Figure 3-2. Comparison of CAP Model PCC 2 Results with Coal Preparation Plant Performance

Flue Gas Desulfurization

The performance of FGD systems is simulated in the CAP model by assuming the use of wet lime/limestone systems having a 90 percent SO_2 removal efficiency (30-day averaging time). Partial scrubbing is assumed in cases where the emission limit can be met by removing less than 90 percent of the SO_2, thereby allowing part or all of the flue gas reheat to be achieved by mixing the scrubbed gas with the bypassed unscrubbed gas. Energy penalties assigned to FGD systems vary between about 5 percent, for cases where all of the flue gas is scrubbed, to about 1 percent, for cases where all of the reheat is provided by the bypassed gas.

Other SO_2 Control Technologies

Although this report discusses only the PCC and FGD simulations, the CAP model can estimate SO_2 reductions for CCC processes, combined PCC and CCC, FBC processes, and low- and medium-Btu coal gasification. A short description of each of these simulations is given below.

Chemical Coal Cleaning. The performance parameters for CCC processes are more rigid than for PCC processes. For different CCC processes, the CAP model user must specify the percentage reduction or threshold value of sulfur (pyritic, organic, and total) in the clean coal. For example, the Meyers process is specified in CAP as reducing the pyritic sulfur to a threshold level of 0.2 percent, with a 5 percent coal energy and 10 percent coal weight loss.

Combined PCC and CCC. PCC/CCC combinations – i.e., multistream processes wherein one PCC or CCC process operates on one of the products of the other – can also be simulated in the CAP model. For example, the Gravichem process is defined as PCC at 14 mesh, 1.3 specific gravity, with the sink product treated with the Meyers CCC process and combined with the float product, which is not chemically cleaned.

Fluidized Bed Combustion. FBC using limestone sorbent is assumed to have a maximum SO_2 removal efficiency of 90 percent. Because of the higher thermal efficiency of FBC systems compared with conventional coal-fired boilers, no energy penalty is assigned when this technology is used for SO_2 control.

Coal Gasification. The low- and medium-Btu coal gasification processes assumed in the CAP model have different SO_2 removal efficiencies and energy penalties as a function of coal type, as summarized in Table 3-2. Coal is categorized as low-volatile or high-volatile on the basis of its ash-free heating value. Coals having an ash-free heating value of less than 13,000 Btu per pound are assumed to be high-volatile C bituminous or subbituminous coals; all other coals are assumed to be medium-volatile or low-volatile.[9]

Table 3-2. Energy Consumed in the Production of Low-Btu and Medium-Btu Gas

Coal Type	Gas Type (in Btu)	SO_2 Control (%)	Energy Loss (% of Input Energy)		
			Process	SO_2 Control	Total
Low-volatile	Low	0 - 92	30.89	1.31	32.20
	Low	92 - 99	29.05	9.80	38.85
	Medium	0 - 99.9	46.20	2.51	48.71
High-volatile	Low	0 - 99	27.92	0.24	28.16
	Medium	0 - 93	40.00	0.77	40.77
	Medium	93 - 99.9	40.00	1.54	41.54

Source: Reference 10.

IMPACT OF TECHNOLOGY AND STANDARDS ON COAL AVAILABILITY

The ability of each SO_2 emission control technology to comply with various SO_2 emission limits when used with coal from northern Appalachia is shown in Figures 3-3 and 3-4. The first figure shows the percentage of northern Appalachian coal reserves able to comply with various emission limits using each of five physical and chemical coal cleaning technologies, while the second figure shows the percentage of the same reserves able to comply with the same limits using the remaining SO_2 control technologies.

The CAP model can evaluate the effect of different SO_2 emission requirements on actual emissions. These emission requirements include emission ceilings, required percentage SO_2 removal, emission floors, and minimum required percentage SO_2 removal. Thus, for example, the CAP model can evaluate the New Source Performance Standard for utility boilers, which includes a 1.2 pound SO_2 per million Btu ceiling, a 90 percent required SO_2 reduction, a 0.6 pound SO_2 per million Btu floor, and a 70 percent minimum SO_2 reduction applicable to low-sulfur coals able to meet the floor with less than 70 percent SO_2 removal. For each specified SO_2 emission limit, the CAP model determines the quantity of coal in a given state or region capable of meeting that limit using each specified SO_2 control technology. Coal energy loss (in the case of coal cleaning) and process energy use are considered in determining the net quantity of coal available to meet each emission limit. For the state-by-state analyses, a continuum of emission limits from 0 to 9.0 lb $SO_2/10^6$ Btu was used, and the percentage of compliance coal was estimated with no SO_2 controls and with PCC and FGD.

Averaging Times

In simulating different emission limits, it is important to take into account that the sulfur content of coal and thus a boiler's SO_2 emissions are not constant and therefore must be associated with an averaging time. A boiler's short-term (e.g., 3-hour) average SO_2 emissions may be twice as high as its long-term average emissions depending on the distribution of sulfur in the coal being used. The results presented in this report are for long-term average (mean) emission limits and coal sulfur contents. A detailed discussion of coal sulfur variability and the conversion between long-term and short-term emission limits is contained in Appendix A. The important aspects of this conversion are summarized below:

- The relative standard deviation, or RSD (standard deviation/mean), of coal sulfur content is often used to define the variability of a boiler's potential SO_2 emissions.
- The major variables that affect compliance with an emission standard are the coal sulfur RSD, the averaging time of the standard, and the frequency with which the standard may be exceeded (e.g., once a month, once a year).
- Higher mean SO_2 content coal may be used to comply with a given SO_2 emission standard if the coal sulfur RSD is small and the averaging time is long.
- Coal cleaning, in addition to reducing coal sulfur content, usually decreases the coal sulfur RSD.
- This study may tend to overestimate the quantity of uncleaned coal, and to a lesser extent cleaned coal, able to meet short-term average emission limits. As a result, the study may understate the benefits of coal cleaning for producing compliance coals.

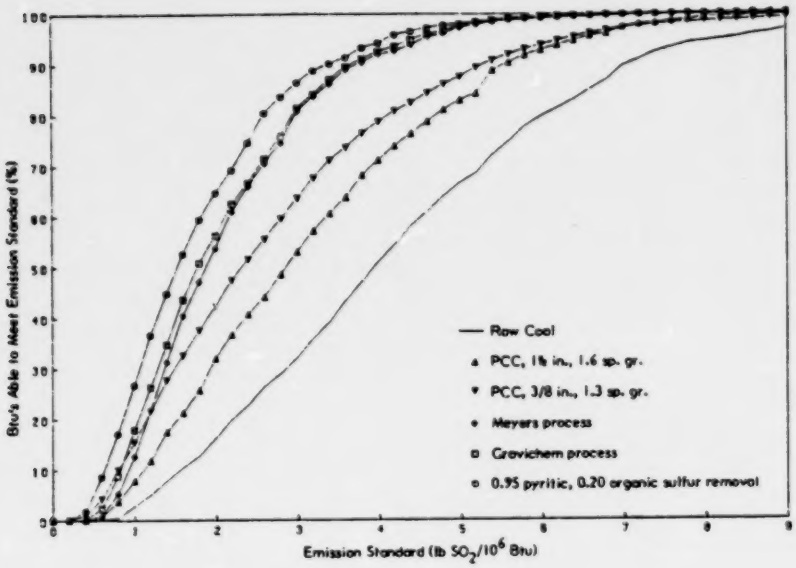

Btu's Able to Meet Emission Standard (%)
Emission Standard (lb SO_2/10^6 Btu)
Raw Coal
PCC, 1¼ in., 1.6 sp. gr.
PCC, 3/8 in., 1.3 sp. gr.
Meyers process
Gravichem process
0.95 pyritic, 0.20 organic sulfur removal

Figure 3-3. Percentage of Coal Reserves in Northern Appalachia Able to Meet Various Emission Limits Using Physical and Chemical Coal Cleaning (Total Coal Reserves = 1,734 Quads)

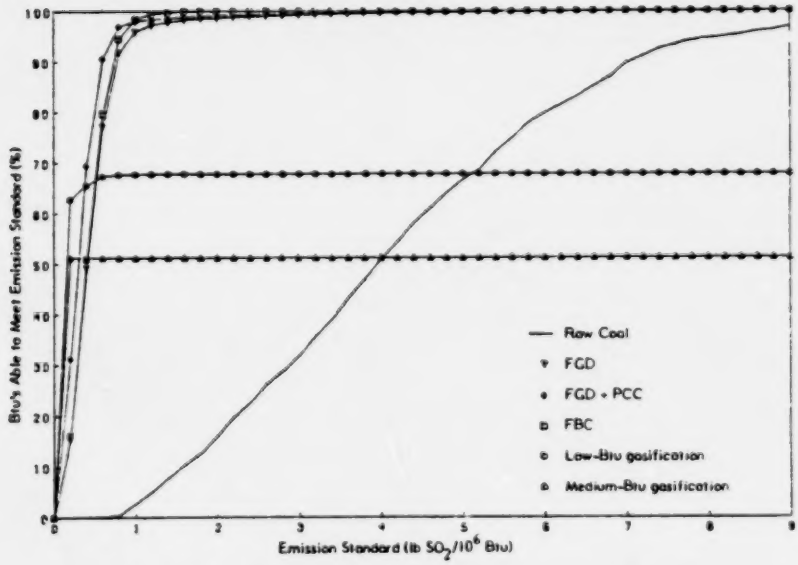


Figure 3-4. Percentage of Coal Reserves in Northern Appalachia Able to Meet Various Emission Limits Using Flue Gas Desulfurization, Fluidized Bed Combustion, and Coal Gasification for SO_2 Control (Total Coal Reserves = 1,734 Quads)

COSTS OF PHYSICAL COAL CLEANING

The CAP model contains algorithms for calculating the levelized costs of physical coal cleaning. The capital and operating cost algorithms are based on 13 PCC plant designs reported by Versar[11] plus cost estimates for landfill disposal of the coal refuse and treatment of collected leachate. The cost of lost coal energy is based on the Btu recovery information in the washability data base (Table 3-1) and on the coal cost. At present the CAP model calculates PCC costs only when operating on the deliveries-to-utilities data base, since this is the only data base that includes detailed information on coal costs.

Levelized PCC capital and operating costs are shown in Figure 3-5 as a function of weight loss. The following factors were used in calculating the levelized costs: (1) a 16 percent fixed charge rate; (2) a 13 percent discount rate; (3) an 8 percent inflation rate; (4) a 1.5 percent real cost escalation rate for coal; (5) no real cost escalation for other labor and materials; and (6) a 20-year plant life.

Figure 3-6 compares the levelized PCC costs calculated by the CAP model with the costs of the 13 PCC plant designs developed by Versar, illustrating that the levelized PCC costs of the CAP model are within 20 percent of the detailed plant design costs. Each state analysis presents the levelized cost of washing for utility coal in 1979 as a function of various emission limits.

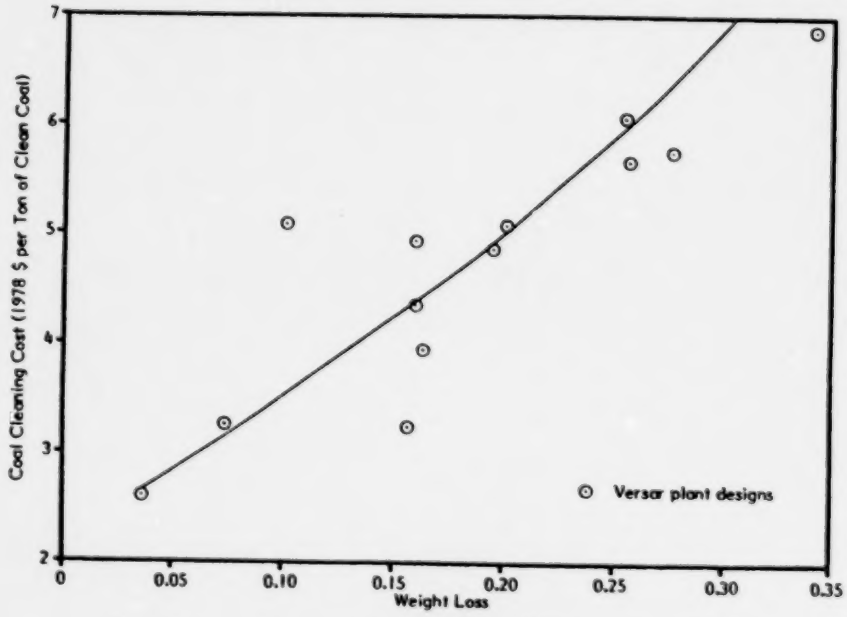


Figure 3-5. Levelized Physical Coal Cleaning Costs in 1978, Exclusive of Lost Coal Energy Cost, as a Function of Weight Loss

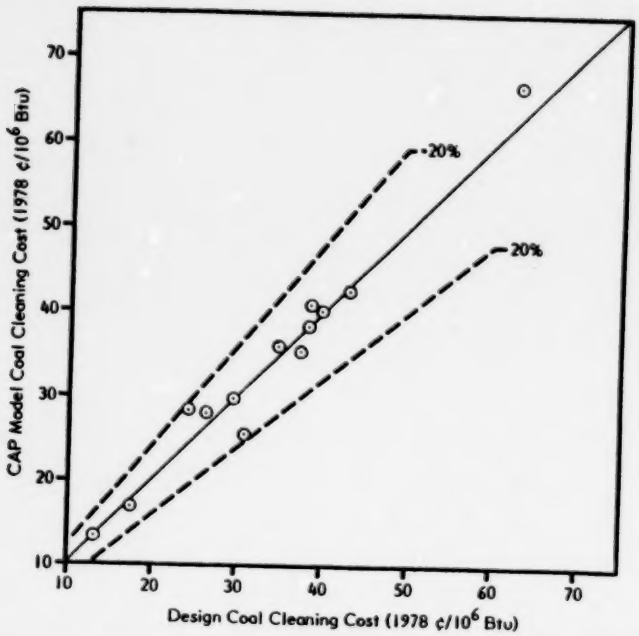


Figure 3-6. **Comparison of CAP Model Levelized Coal Cleaning Cost with Thirteen Plant Design Costs (Including Cost of Lost-Coal Energy at $1/10^6 Btu)**

SECTION 3 REFERENCES

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4. STATE ANALYSES

4.1 ALABAMA

General Information

The Alabama coal fields are located in the northern third of the state, with most of the production coming from counties near Birmingham. A lignite belt with a generally east-west orientation exists in southern Alabama; this belt, however, has little economic significance. Strip mining produced 15 million tons of coal in Alabama in 1977, while underground mining produced about 7 million tons. About 3 million tons of Alabama coal in 1977 were used as metallurgical coal for producing coke.[1]

About one-half of the Alabama coal was shipped by rail or water in 1977 while 35 percent was shipped by truck and 10 percent was used in minemouth generating plants.[1]

Pertinent facts regarding Alabama coal properties are listed in Figure 4.1-1. The coal properties, taken from the coal data bases described in Section 3, are specified on a moisture-free basis for the reserves and production data bases and on an as-delivered basis for the deliveries-to-utilities data base.

Coal Employment and Production in 1977

County	Production (10^3 Tons) Underground*	Surface*	Total*	Value (10^6 $)*	Number of Employees (Monthly Average)**
Walker	2,513	4,296	6,809	175	2,664
Jefferson	3,211	2,200	5,411	190	3,814
Tuscaloosa	57	3,614	3,671	94	1,180
Fayette	780	245	1,025	21	622
Others	35	4,590	4,625	142	2,014
TOTAL	6,596	14,949	21,545	622	10,294

* Source: Reference 1.

** Source: Reference 2.

Coal Washing in 1977

Alabama coals are generally low in sulfur, about half of which is pyritic and therefore amenable to removal by physical coal cleaning. In 1977, 29 coal cleaning plants processed about 40 percent of the coal mined in Alabama.[1] The level of cleaning by these plants is unknown.

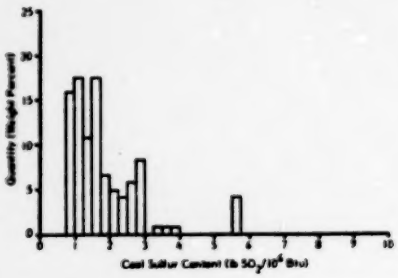
Coal Washability Data

Pertinent facts regarding the washability of Alabama coals, taken from the washability data base described in Section 3, are listed here in Figure 4.1-2. The top portion of the figure provides information regarding the coal properties on a moisture-free basis before and after physical cleaning. Two levels of cleaning, PCC I and PCC II, are analyzed. The bottom portion of the figure summarizes the potential SO_2 emission reduction and energy recovery characteristics of the coals in the washability data base at the two levels of cleaning.

Figure 4.1-1. Alabama Coal Properties Fact Sheet

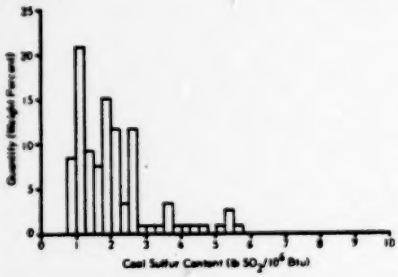
Reserves: 2,972 million tons, 78.5 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,532	1.28	10.50
Std. Dev.	797	0.72	5.07
Minimum	11,510	0.50	1.10
Maximum	15,370	3.90	21.40



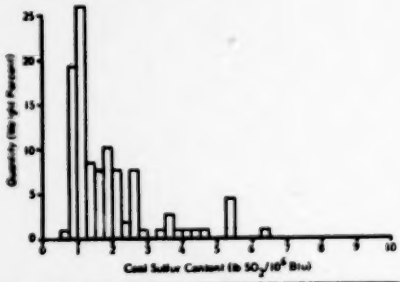
1976 Production: 21.06 million tons, 0.57 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,629	1.34	9.66
Std. Dev.	698	0.68	3.61
Minimum	11,660	0.40	3.20
Maximum	15,150	3.90	20.00



Projected 1985 Production: 32.08 million tons, 0.85 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,667	1.23	9.88
Std. Dev.	682	0.73	3.36
Minimum	11,660	0.40	3.20
Maximum	15,150	3.90	20.00



1979 Deliveries to Utilities: 14.59 million tons, 0.35 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,003	1.50	13.23
Std. Dev.	545	0.67	2.53
Minimum	9,732	0.30	3.30
Maximum	13,784	9.00	24.00

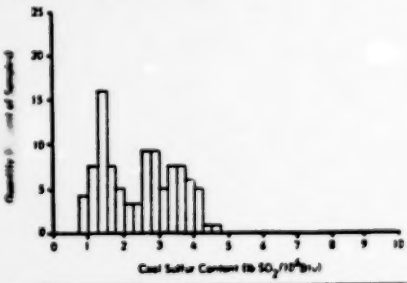
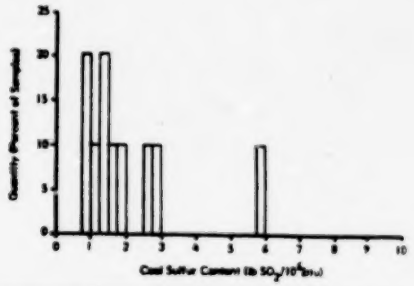


Figure 4.1-2. Alabama Coal Washability Data Sheet

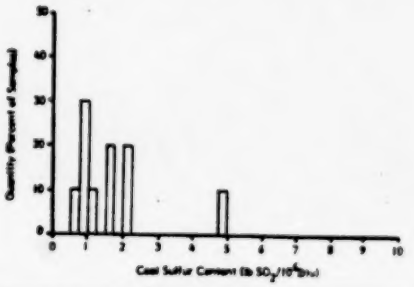
Raw Coal: 10 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,696	1.33	9.50
Std. Dev.	914	0.95	6.38
Minimum	12,765	0.59	1.73
Maximum	15,056	3.76	16.27



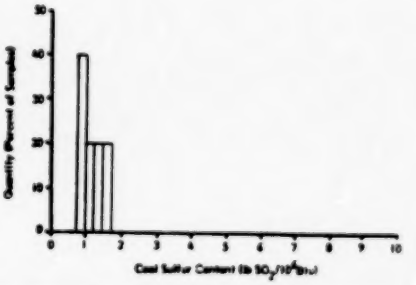
PCC I: 1-1/2 in., 1.6 sp. gr., 10 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,213	1.21	6.09
Std. Dev.	657	0.84	4.49
Minimum	13,278	0.57	1.50
Maximum	15,230	3.40	14.10



PCC II: 3/8 in., 1.3 sp. gr., 10 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,750	0.87	2.57
Std. Dev.	344	0.23	1.33
Minimum	14,286	0.61	1.10
Maximum	15,349	1.26	4.80



SO_2 Emission Reduction and Energy Recovery:

	SO_2 Emission Reduction (%)		Btu Recovery (%)	
	PCC I	PCC II	PCC I	PCC II
Mean	10.8	25.5	96.4	63.2
Std. Dev.	8.1	22.8	3.1	29.2
Minimum	0	2.0	90.3	18.0
Maximum	25.0	72.0	99.7	93.4

Alabama Coal Seams

The coal deposits in Alabama are divided into four fields: the Coosa, Cahaba, Plateau, and Warrior. Most of the state's current production comes from the Warrior field. Within each field there are a large number of coal beds, each of which contains many seams. The major producing coal beds, all in the Warrior field, are discussed below.[3]

Mary Lee Coal. The Mary Lee Coal group, the largest producing group in the state, includes the Blue Creek, Jagger, Mary Lee, Mt. Carmel, Newcastle, and Ream beds in Jefferson, Tuscaloosa, and Walker counties. These beds are mined by both underground and surface methods. The Mary Lee bed varies from four to eight feet in thickness and contains many partings, which must be removed by washing; the bed has a strong, sandy shale or sandstone top and a fireclay or shale bottom. The Mt. Carmel bed is an upper split of the Mary Lee. The Blue Creek bed varies from six to eight feet in thickness and has a sandy shale top and shale bottom, while the Jagger bed is less than six feet thick. Both the Blue Creek and Jagger coals are used for coking as well as for general steam and domestic purposes.[3]

Pratt Coal. This group, the second largest producer in the state, includes the American, Curry, Gillespie, and Pratt beds mined by surface and underground methods in Jefferson and Walker counties. The principal beds in this group are the Pratt (known in the western part of the basin as the Corona) and the American (known in the western part of the basin as the Nickel Plate). The Pratt bed, between three and six feet thick, contains a two-to-three-inch-thick parting near the top. The roof and floor of this bed are usually sandstone. This bed is one of the major sources of coking coal in Alabama. The Nickel Plate bed averages about three feet in thickness and has a two-inch-thick parting near the top. This bed has a hard shale top and a smooth fireclay floor. The American bed is generally thicker than the Nickel Plate and contains more partings.[3]

Brookwood Coal. This group includes the Brookwood, Carter, and Milldale beds, which are mined by surface methods in Tuscaloosa County. In thickness, the Brookwood bed can reach seven feet, while the Carter and Milldale beds seldom exceed three feet. Beds in the Brookwood group typically have a shale roof and floor and at least one parting, which is removed with the coal. Coal from this group is used for both coking and steam generation.[3]

Black Creek Coal. This group includes the Black Creek, Jefferson, and Lick Creek beds and is mined by both surface and underground methods. Both the Black Creek and Jefferson beds are between one and seven feet thick and are overlain by a shale top. The Black Creek coal has a fireclay bottom, while the Jefferson is underlain by either shale or sandstone.[3]

Cobb Coal. The Cobb coal group consists of the lower Cobb and the upper Cobb coal beds. Both beds are fairly persistent and crop out extensively across the central part of the field. The thickness of either bed rarely exceeds two feet, but both have been mined.[3]

Estimates of Alabama Coal Available to Meet Various SO_2 Emission Regulations

Figure 4.1-3 shows the percentage of projected 1985 Alabama coal production excluding metallurgical coal able to meet various emission standards before cleaning, after cleaning at each of three levels, and when used in conjunction with an FGD system. Much of the Alabama coal can comply with relatively low emission limits without cleaning. If 95 percent of the pyritic and 20 percent of the organic sulfur were removed by a hypothetical chemical coal cleaning process, almost all of the Alabama coal could comply with a 1 lb $SO_2/10^6$ Btu emission standard.

Figure 4.1-4 shows the percentage of the projected 1985 Alabama coal production excluding metallurgical coal able, when physically cleaned, to meet a standard stipulating both an SO_2 emission ceiling and a percentage SO_2 reduction. (The circled number next to each curve shows the value of the emission ceiling in lb $SO_2/10^6$ Btu.) The curves in this figure show again that Alabama coals can comply with relatively low emission limits but that they are not able to comply with regulations requiring a large percentage SO_2 reduction.

Table 4.1-1 shows the potential SO_2 emissions, percentage SO_2 reduction, and cost of compliance for an SO_2 emission regulation requiring physical cleaning at 1½ inch top size and 1.6 specific gravity of those coals mined in Alabama for utility use in 1979 that had sulfur contents exceeding a specified floor.

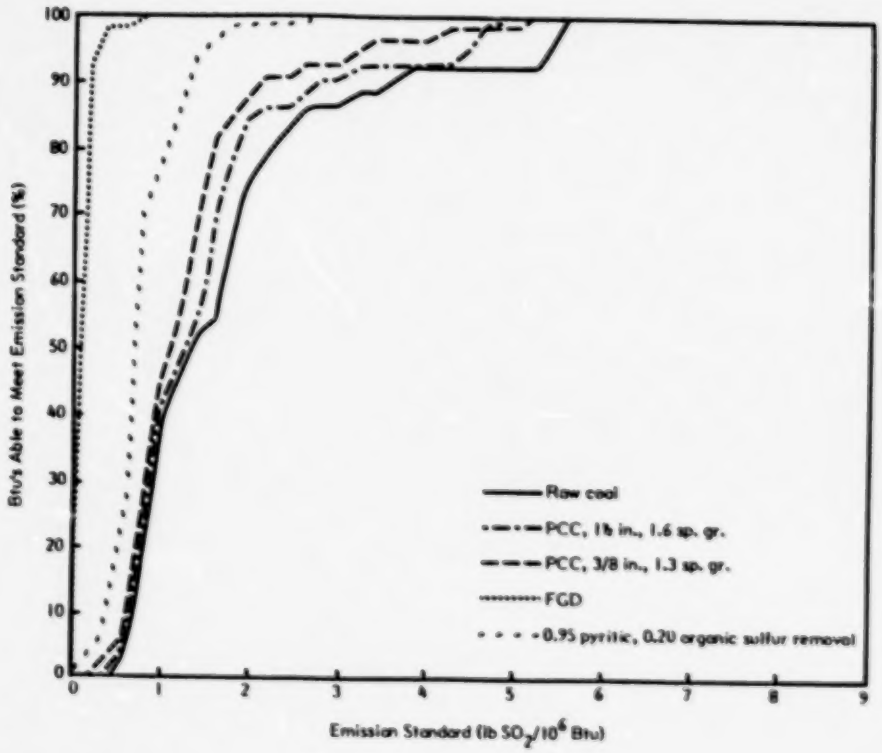


Figure 4.1-3. **Percentage of Projected 1985 Alabama Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization**

Figure 4.1-4. Percentage of Projected 1985 Alabama Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1.6 sp. gr.

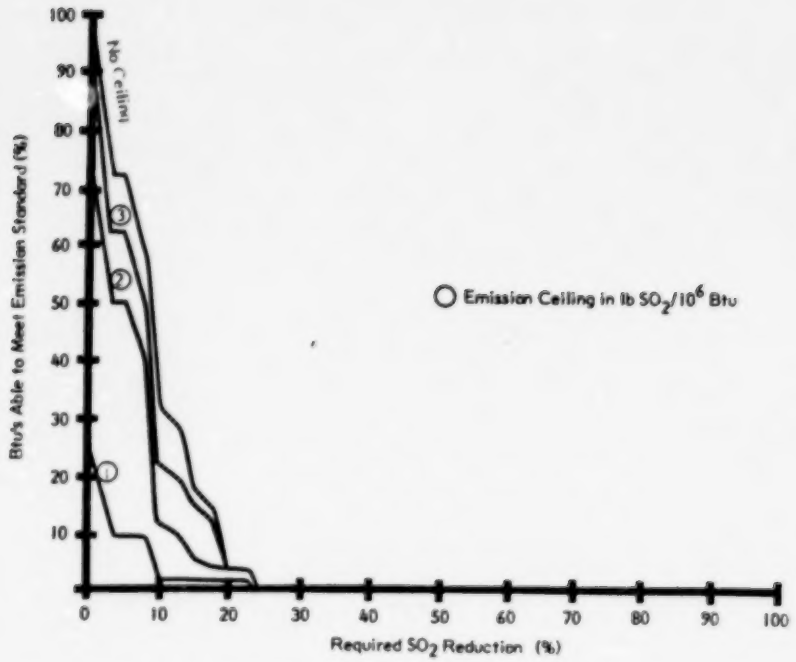


Table 4.1-1. Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Alabama Coals Delivered to Utilities in 1979

Coals to Be Washed*	Quantity to Be Washed (10^3 Tons)	Total SO_2 Emissions after Selective Washing (10^3 Tons)	SO_2 Emission Reduction Achieved by Selective Washing		Levelized Cost of Washing (10^6 1979$)	Cost Effectiveness ($/Tons SO_2)
			(10^3 Tons)	(%)		
No coals	0	345	0	0	0	0
Coals with SO_2 contents above floor of:						
4 lb/10^6 Btu	1,096	334	11	3	9	820
3 lb/10^6 Btu	4,823	297	48	14	41	850
2 lb/10^6 Btu	7,213	281	64	19	62	970
1 lb/10^6 Btu	9,986	273	72	21	85	1,180
All coals	10,295	273	72	21	89	1,240

* Excluding the 4,293,000 tons of coal actually washed in 1979.

Major Sources of Coal Used by Alabama Utility Plants in 1979

Source states for coal delivered to Alabama utilities in 1979 are listed in Table 4.1-2 along with the quantity and the weighted average sulfur and ash content of the coal from each state. Table 4.1-3 shows the Alabama utility plants that imported the greatest amount of coal in 1979, ranked according to the quantity imported. Following the plant name, the combined units' size and SO_2 limits are shown. In some cases, more than one SO_2 limit applies to various units of a given plant. The remaining columns indicate the quantity imported from each state, the percentage of coal that quantity represented for each plant, and the weighted average sulfur and ash content of the imported coal.

Table 4.1-2. Source State for Coal Used in Alabama Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Alabama	12,659	70	1.41	13.4	2.35
Kentucky	3,415	19	2.55	12.8	4.40
Tennessee	721	4	1.84	12.7	3.02
Ohio	548	3	2.13	11.8	3.66
Indiana	440	2	1.74	10.3	3.16
West Virginia	243	1	1.79	12.8	2.90
Remaining States	115	1	2.19	11.4	3.76
TOTAL	18,141	100	1.68	13.2	2.84

Table 4.1-3. Out-of-State Coal Use by Alabama Plants in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	State of Origin	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
						Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Colbert	1,286	4.0	KY	964	40	1.76	12.3	3.06
Colbert	1,286	4.0	OH	548	23	2.13	11.8	3.66
Colbert	1,286	4.0	IN	434	18	1.75	10.3	3.18
Colbert	1,286	4.0	WV	202	8	2.00	12.8	3.23
Colbert	1,286	4.0	TN	104	4	2.35	13.2	3.86
Widows Creek	1,826	0.5, 1.1	KY	2,011	57	3.22	13.0	5.53
Widows Creek	1,826	0.5, 1.1	TN	235	7	1.32	13.6	2.13
Gaston	1,912	1.2, 4.0	TN	339	7	2.14	11.9	3.53
Tombigbee	545	1.2, 4.0	KY	180	30	1.15	14.9	2.03
Barry	1,566	1.8	KY	174	18	0.89	12.2	1.52
Remaining Plants	–	–	–	291	4	1.66	12.0	3.21
TOTAL	9,151	–	–	5,482	30	2.30	12.5	3.97

Major Utility Users of Alabama Coal in 1979

Table 4.1-4 lists the states containing utility plants that burned Alabama coal in 1979. Also listed are the Alabama coal quantities received, the percentage of coal use these quantities represented for each state, and the weighted average coal properties. The largest Alabama users of Alabama coal are listed in Table 4.1-5 along with relevant plant information and coal properties.

Table 4.1-4. States Receiving Alabama Coal Deliveries to Utility Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Alabama	12,659	70	1.41	13.4	2.35
Georgia	713	4	1.65	11.7	2.66
Mississippi	686	25	2.28	12.0	3.72
Florida	527	9	2.32	12.0	3.83
Tennessee	4	< 1	1.68	16.5	2.92
TOTAL	14,588	–	1.50	13.2	2.48

Table 4.1-5. Alabama Utility Plants Receiving Alabama Coal Deliveries in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
					Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Gorgas	1,317	4.0	4,472	100	1.28	13.6	2.14
Gaston	1,912	1.2, 4.0	4,263	90	1.83	13.4	3.06
Widows Creek	1,826	0.5, 1.1	1,256	36	0.82	16.4	1.38
Miller	662	1.2	726	100	0.67	8.4	1.05
Barry	1,566	1.8	713	74	0.94	13.0	1.57
Greene	518	4.0	452	100	1.73	10.7	2.79
Tombigbee	545	1.2, 4.0	423	70	1.35	15.3	2.40
Gadsden	136	4.0	266	98	2.29	12.8	3.69
Colbert	1,286	4.0	89	4	2.27	13.7	3.78
TOTAL	9,151	–	12,659	70	1.41	13.4	2.35

4.2 ILLINOIS

General Information

All of Illinois except the northern quarter of the state is underlain by coal, with the majority of the production coming from the southern part of the state. In 1977, Illinois was the fourth largest coal-producing state behind Kentucky, West Virginia, and Pennsylvania. Strip mining produced about 24 million tons in 1977 while underground mining produced about 29 million tons. Nearly 3 million tons of Illinois coal in 1977 were used as metallurgical coal for producing coke.[1]

Eighty-three percent of the Illinois coal was shipped by rail or water in 1977 while 12 percent was shipped by truck and 5 percent was used in minemouth generating plants.[1]

Pertinent facts regarding Illinois coal properties are listed in Figure 4.2-1. The coal properties, taken from the coal data bases described in Section 3, are specified on a moisture-free basis for the reserves and production data bases and on an as-delivered basis for the deliveries-to-utilities data base.

Coal Employment and Production in 1977

County	Production (10^3 Tons) Underground*	Surface*	Total*	Value (10^6 $)*	Number of Employees (Monthly Average)**
Perry	0	9,571	9,571	128	1,533
Randolph	2,383	4,581	6,964	113	2,016
Jefferson	4,334	434	4,768	***	2,348
Franklin	4,751	0	4,751	***	1,779
Macoupin	3,623	0	3,623	***	977
Christian	2,808	0	2,808	49	916
Fulton	0	2,680	2,680	55	854
Williamson	1,333	839	2,172	44	1,197
Douglas	2,688	0	2,688	48	801
Others	7,491	5,977	13,468	***	3,693
TOTAL	29,411	24,082	53,493	924	16,114

* Source: Reference 1.

** Source: Reference 4.

*** Witheld to avoid disclosing individual companies' confidential data.

Coal Washing in 1977

Illinois coals are very amenable to sulfur reduction by physical coal cleaning methods. In 1977, 37 coal cleaning plants processed 78 percent of the coal produced in Illinois.[1] The level of cleaning by these plants is unknown.

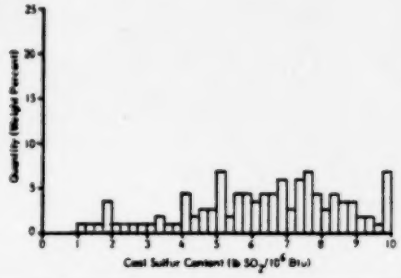
Coal Washability Data

Pertinent facts regarding the washability of Illinois coals, taken from the washability data base described in Section 3, are listed here in Figure 4.2-2. The top portion of the figure provides information regarding the coal properties on a moisture-free basis before and after physical cleaning. Two levels of cleaning, PCC I and PCC II, are analyzed. The bottom portion of this figure summarizes the potential SO_2 emission reduction and energy recovery characteristics of the coals in the washability data base at the two levels of cleaning.

Figure 4.2-1. Illinois Coal Properties Fact Sheet

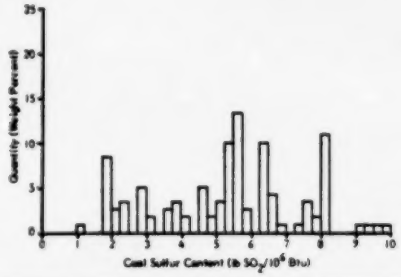
Reserves: 65,626 million tons, 1,465 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,271	3.92	13.52
Std. Dev.	676	1.27	4.13
Minimum	9,710	0.50	4.70
Maximum	13,880	9.50	30.50



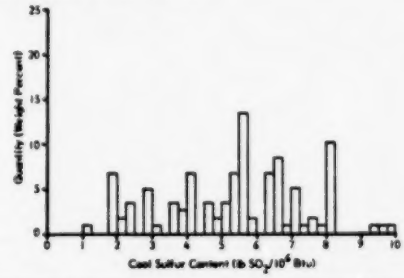
1976 Production: 57.82 million tons, 1.41 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,209	3.24	11.53
Std. Dev.	808	1.24	2.09
Minimum	10,281	0.80	6.20
Maximum	13,657	6.70	18.00



Projected 1985 Production: 92.63 million tons, 2.05 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,279	3.30	11.61
Std. Dev.	743	1.20	2.08
Minimum	10,281	0.80	6.20
Maximum	13,657	6.70	18.00



1979 Deliveries to Utilities: 49.51 million tons, 1.08 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	10,857	2.81	10.72
Std. Dev.	627	0.73	2.78
Minimum	8,000	0.26	2.07
Maximum	12,700	5.28	33.50

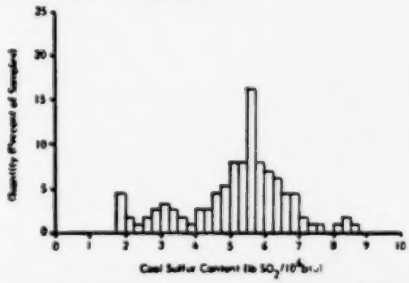
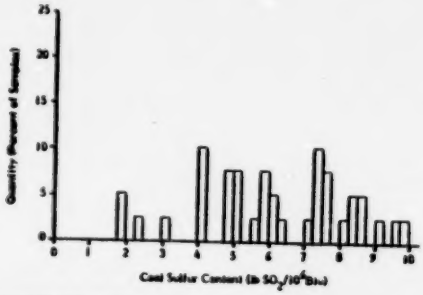


Figure 4.2-2. Illinois Coal Washability Data Sheet

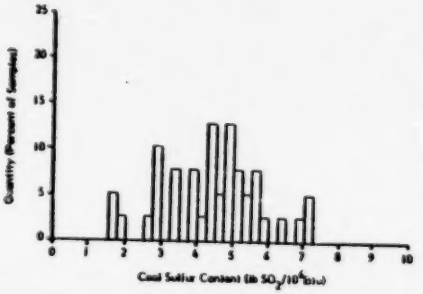
Raw Coal: 40 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	11,944	3.86	15.29
Std. Dev.	683	1.39	4.45
Minimum	10,777	1.14	7.63
Maximum	13,294	7.82	25.03



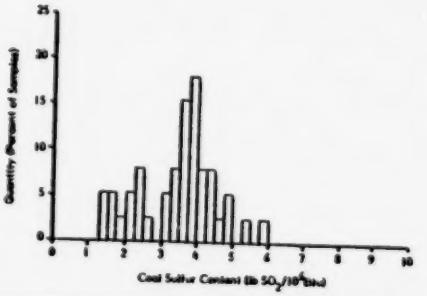
PCC I: 1-1/2 in., 1.6 sp. gr., 40 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,901	2.84	8.50
Std. Dev.	286	0.87	1.42
Minimum	12,390	0.99	5.40
Maximum	13,544	4.56	11.40



PCC II: 3/8 in., 1.3 sp. gr., 40 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,529	2.33	4.02
Std. Dev.	281	0.70	1.06
Minimum	13,023	0.91	2.80
Maximum	14,042	3.89	6.80



Emission Reduction vs. Energy Recovery:

	Emission Reduction (%)		Btu Recovery (%)	
	PCC I	PCC II	PCC I	PCC II
Mean	29.3	43.5	94.9	50.9
Std. Dev.	13.9	14.4	2.3	13.0
Minimum	2.0	13.0	89.3	19.1
Maximum	57.0	68.0	99.3	75.5

Illinois Coal Seams

Herrin (No. 6) Coal. The No. 6 coal bed is the third largest coal-producing bed in the United States and is mined in Illinois, western Kentucky, Indiana, and Missouri.[1] Illinois No. 6 coal has been correlated with Indiana No. 6 and Kentucky No. 11. It is by far the major producing seam in Illinois, representing 45 million tons, or 84 percent, of the state's 1977 production.[4] The No. 6 coal is subdivided into fairly persistent benches, between some of which occur clay bands of great persistence. The most widely occurring clay band is called the "blue band," commonly located one to two feet above the base of the coal and typically one to two inches thick (although much thicker in some areas). In many areas of southwestern Illinois, a fairly persistent layer of pyrite or of pyrite and clay combined occurs a few inches above the blue band. The No. 6 coal usually persists in a thickness of between five and six feet and generally has a black slate roof overlaid by a fairly thick limestone caprock. The No. 6 coal of lowest sulfur and ash content is located in the Franklin-Williamson-Jefferson county district known as the "Quality Circle" and is between 8 and 14 feet thick. The "Quality Circle" area covers about 250 square miles and is about 60 to 70 percent mined out.[3] The No. 6 bed was mined by both strip and pillar and room methods in 46 mines in 1977.[4]

Harrisburg-Springfield (No. 5) Coal. In 1977 this coal bed accounted for nearly 7 million tons, or about 13 percent, of Illinois production.[4] Illinois No. 5 coal has been correlated with Indiana No. 5 and Kentucky No. 9. These coals represent the second largest coal-producing bed in the United States.[1] The No. 5 coal is the most extensively mined coal in western Illinois and has also been mined in the southwestern portion of the state. Usually this coal has a thickness of between four and six feet but may occur in deposits as thick as ten feet. No. 5 coal of relatively low sulfur content is located in southeastern Illinois. The No. 5 coal in western Illinois and the Springfield area is characterized by numerous claystone dikes, which may cut through the seam from top to bottom. These irregularities may significantly influence the purity of the coal and the quality of the roof strata.[3] Four pillar and room mines and ten strip mines were producing coal from the No. 5 bed in 1977.[4]

Colchester (No. 2) Coal. Two strip mines produced about 622,000 tons of No. 2 coal, or about 1 percent of Illinois coal production, in 1977.[4] No. 2 coal has been mined principally in northern and western Illinois, where seam thickness varies between two and four feet. Throughout the remainder of the state, the seam, where it exists, varies in thickness from a few inches to about two feet. The immediate floor is commonly an underclay without special refractory characteristics. However, in northern Illinois the immediate underclay overlies refractory clay of economic importance.[3]

Davis-DeKovan Coal. One strip mine produced about 531,000 tons of Davis-DeKovan coal in 1977.[4] The DeKovan and Davis coal seams are commonly 10 to 25 feet apart and are usually strip mined simultaneously. Each seam is typically three to four feet thick. These coals were mined for many years in small operations along their outcrop in southern Illinois.[3]

Estimates of Illinois Coal Available to Meet Various SO_2 Emission Regulations

Figure 4.2-3 shows the percentage of projected 1985 Illinois coal production excluding metallurgical coal able to meet various emission standards before cleaning, after cleaning at each of three levels, and when used in conjunction with an FGD system. Illinois coal is high in sulfur, and less than half of the raw coal can comply with a 5 lb $SO_2/10^6$ Btu emission limit. Physical cleaning significantly increases the quantity of Illinois coal able to comply with a given SO_2 emission limit. If 95 percent of the pyritic and 20 percent of the organic sulfur were removed by a hypothetical chemical coal cleaning process, more than one-half of the Illinois coal could comply with a 3 lb $SO_2/10^6$ Btu emission standard.

Figure 4.2-4 shows the percentage of the projected 1985 Illinois coal production excluding metallurgical coal able, when physically cleaned, to meet a standard stipulating both an SO_2 emission ceiling and a percentage SO_2 reduction. (The circled number next to each curve shows the value of the emission ceiling in lb $SO_2/10^6$Btu.) The curves in this figure show that physical coal cleaning can reduce the sulfur content of most of the coal in Illinois by at least 20 percent, and some of the coal by nearly 50 percent. The high sulfur content of Illinois coal, however, does not allow much of it to comply with a combined percentage SO_2 reduction and a low SO_2 ceiling when physical coal cleaning is used for SO_2 control.

Table 4.2-1 shows the potential SO_2 emissions, percentage SO_2 reduction, and cost of compliance for an SO_2 emission regulation requiring physical cleaning at 1½ inch top size and 1.6 specific gravity of those coals mined in Illinois for utility use in 1979 that had sulfur contents exceeding a specified floor.

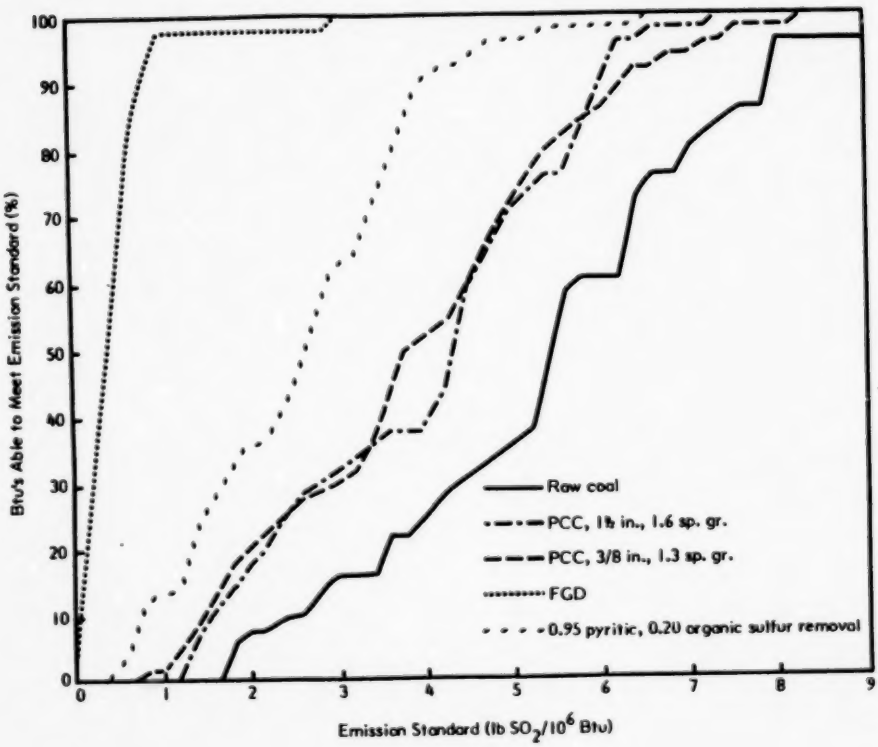


Figure 4.2-3. Percentage of Projected 1985 Illinois Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization

Figure 4.2.A. Percentage of Projected 1985 Illinois Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1¼", 1.6 sp. gr.

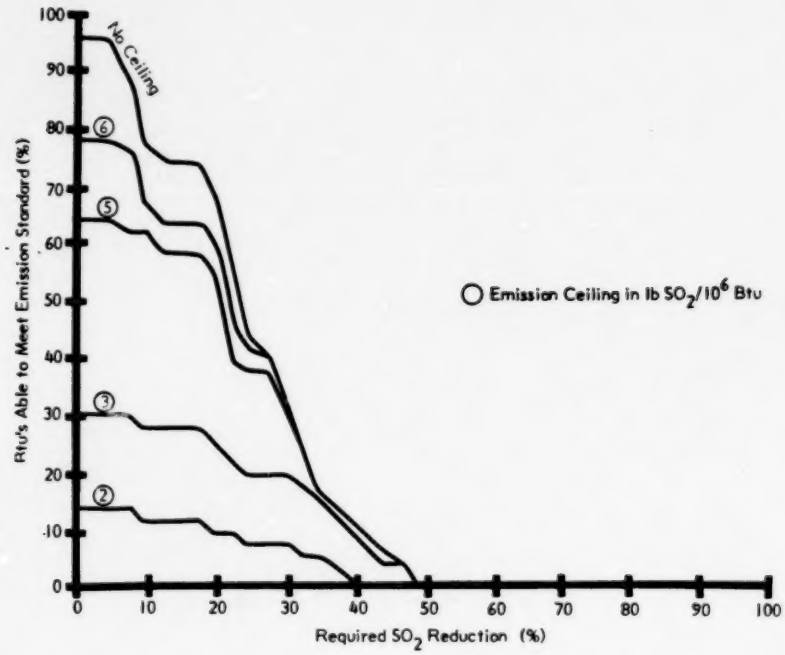


Table 4.2-1. Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Illinois Coals Delivered to Utilities in 1979

Coals to Be Washed*	Quantity to Be Washed (10^3 Tons)	Total SO_2 Emissions after Selective Washing (10^3 Tons)	SO_2 Emission Reduction Achieved by Selective Washing		Levelized Cost of Washing (10^6 1979$)	Cost-Effectiveness ($/Ton SO_2)
			(10^3 Tons)	(%)		
No coals	0	819	0	0	0	–
Coals with SO_2 contents above floor of:						
7 lb/10^6Btu	2,055	760	59	7	17	290
6 lb/10^6Btu	5,045	715	105	13	36	340
5 lb/10^6 Btu	8,500	643	176	22	65	370
4 lb/10^6 Btu	11,444	606	214	26	85	400
All coals	15,089	585	234	29	100	430

* Excluding the 34,423,000 tons of coal actually washed in 1979.

Major Sources of Coal Used by Illinois Utility Plants in 1979

Source states for coal delivered to Illinois utilities in 1979 are listed in Table 4.2-2 along with the quantity and the weighted average sulfur and ash content of the coal from each state. Table 4.2-3 shows the Illinois utility plants that imported the greatest amount of coal in 1979, ranked according to the quantity imported. Following the plant name, the combined units' size and SO_2 limits are shown. In some cases, more than one SO_2 limit applies to various units of a given plant. The remaining columns indicate the quantity imported from each state, the percentage of coal that quantity represented for each plant, and the weighted average sulfur and ash content of the imported coal.

Table 4.2-2. Source State for Coal Used in Illinois Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Illinois	18,408	51	3.12	11.4	5.97
Wyoming	9,173	25	0.46	6.5	0.97
Montana	4,022	11	0.45	5.3	0.97
Colorado	1,762	5	0.60	9.4	1.07
Kentucky	1,566	4	1.51	8.8	2.64
Indiana	1,080	3	1.98	9.8	3.60
Remaining States	389	1	1.34	11.4	2.21
TOTAL	36,401	100	1.91	9.2	3.67

Table 4.2-3. Out-of-State Coal Use by Illinois Plants in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	State of Origin	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
						Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Joliet	1,405	1.8	WY	2,946	79	0.53	7.2	1.11
Joliet	1,405	1.8	MT	801	21	0.39	4.2	0.83
Powerton	1,700	1.8	WY	2,514	63	0.37	6.1	0.78
Powerton	1,700	1.8	MT	914	23	0.40	4.3	0.84
Will County	1,058	1.8	WY	1,419	66	0.47	4.8	1.00
Will County	1,058	1.8	MT	727	34	0.40	4.3	0.85
Waukegan	694	1.8	WY	1,427	83	0.47	8.5	0.98
Edwards	756	1.8	MT	687	52	0.68	10.5	1.58
Edwards	756	1.8	CO	641	48	0.57	9.8	0.96
Wood River	506	1.8	CO	812	100	0.62	9.8	1.11
Remaining Plants	–	–	–	5,104	46	1.17	7.7	2.12
TOTAL	15,592	–	–	17,992	49	0.67	7.0	1.32

Major Utility Users of Illinois Coal in 1979

Table 4.2-4 lists the states containing utility plants that burned Illinois coal in 1979. Also listed are the Illinois coal quantities received, the percentage of coal use these quantities represented for each state, and the weighted average coal properties. The largest Illinois users of Illinois coal are listed in Table 4.2-5 along with relevant plant information and coal properties.

Table 4.2-4. States Receiving Illinois Coal Deliveries to Utility Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Illinois	18,408	51	3.12	11.4	5.97
Missouri	11,434	53	2.51	10.3	4.55
Indiana	6,427	18	2.73	11.3	5.11
Wisconsin	3,697	30	2.73	9.7	4.94
Georgia	3,326	17	2.52	9.3	4.45
Iowa	1,975	17	2.72	9.2	5.16
Florida	1,448	25	2.51	9.8	4.27
Michigan	830	3	3.11	9.8	5.57
Minnesota	688	5	2.82	9.4	5.03
Kentucky	504	2	3.22	16.8	6.18
Tennessee	445	2	2.25	10.6	3.91
Mississippi	261	10	2.57	11.1	4.27
Alabama	70	< 1	2.35	9.9	4.08
TOTAL	49,513	–	2.81	10.7	5.22

Table 4.2-5. Illinois Utility Plants Receiving Illinois Coal Deliveries in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
					Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Baldwin	1,815	5.8	4,785	96	3.00	11.3	5.66
Kincaid	1,212	8.1	2,752	100	3.52	10.3	6.94
Coffeen	878	4.6	2,399	100	3.74	17.4	7.90
Joppa	1,015	3.6	1,728	57	2.11	9.0	3.58
Duck Creek	390	1.2	1,118	100	3.36	8.8	6.37
Newton	590	1.2	1,014	72	2.96	11.6	5.19
Marion	271	1.2, 4.3	812	100	3.01	14.9	5.82
Meredosia	557	1.6, 5.2	795	100	2.91	5.6	5.14
Dallman	364	1.2, 6.2	721	100	3.24	9.6	6.18
Hennepin	316	5.8	604	74	2.95	10.1	5.35
Remaining Plants	–	–	1,681	21	3.06	11.3	5.74
TOTAL	15,592	–	18,408	51	3.12	11.4	5.97

4.3 INDIANA

General Information

The Indiana coal fields are located in the southwestern portion of the state, with most of the production coming from the southern counties in the field. Strip mining produced about 27 million tons of coal in Indiana in 1977, while underground mining produced less than 1 million tons. None of the coal produced in Indiana in 1977 was used for the production of coke.[1]

About two-thirds of the Indiana coal in 1977 was shipped by rail or water, while one-third was shipped by truck, and only 3 percent was used by minemouth generating plants.[1]

Pertinent facts regarding Indiana coal properties are listed in Figure 4.3-1. The coal properties, taken from the coal data bases described in Section 3, are specified on a moisture-free basis for the reserves and production data bases and on an as-delivered basis for the deliveries-to-utilities data base.

Coal Employment and Production in 1977

County	Production (10^3 Tons) Underground*	Surface*	Total*	Value (10^6 $)**	Number of Employees (Monthly Average)**
Warrick	464	8,979	9,443	129	–
Pike	34	6,777	6,811	92	–
Sullivan	0	3,358	3,358	***	–
Vermillion	0	2,420	2,420	***	–
Clay	0	1,398	1,398	23	–
Spencer	0	1,101	1,101	16	–
Greene	27	1,010	1,037	16	–
Others	0	2,427	2,427	***	–
TOTAL	525	27,470	27,995	387	3,942

* Source: Reference 5.

** Source: Reference 1.

*** Withheld to avoid disclosing individual companies' confidential data.

Coal Washing in 1977

Indiana coals, because of their high pyritic sulfur content, are very amenable to sulfur reduction by physical coal cleaning methods. In 1977, 14 coal cleaning plants processed 73 percent of the coal produced in Indiana.[1] The level to which these coals were cleaned is unknown.

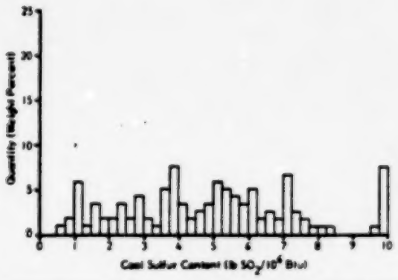
Coal Washability Data

Pertinent facts regarding the washability of Indiana coals, taken from the washability data base described in Section 3, are listed here in Figure 4.3-2. The top portion of the figure provides information regarding the coal properties on a moisture-free basis before and after physical cleaning. Two levels of cleaning, PCC I and PCC II, are analyzed. The bottom portion of the figure summarizes the potential SO_2 emission reduction and energy recovery characteristics of the coals in the washability data base at the two levels of cleaning.

Figure 4.3-1. Indiana Coal Properties Fact Sheet

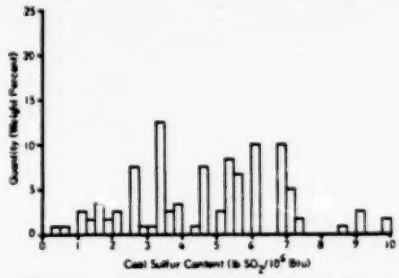
Reserves: 10,607 million tons, 244 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,854	3.16	10.66
Std. Dev.	524	1.59	2.84
Minimum	10,740	0.50	3.30
Maximum	14,440	8.20	23.90



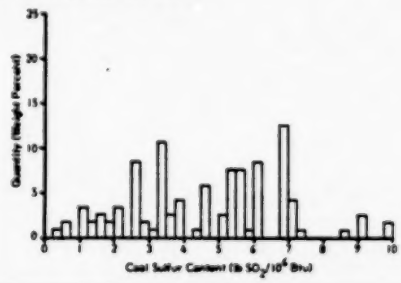
1976 Production: 25.79 million tons, 0.66 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,886	3.06	10.17
Std. Dev.	362	1.36	1.27
Minimum	11,320	0.50	8.60
Maximum	13,850	6.70	17.60



Projected 1985 Production: 30.62 million tons, 0.70 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,886	3.06	10.14
Std. Dev.	354	1.37	1.20
Minimum	11,320	0.20	8.60
Maximum	13,850	6.70	17.60



1979 Deliveries to Utilities: 25.32 million tons, 0.55 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	10,867	2.78	10.72
Std. Dev.	369	0.94	1.82
Minimum	8,202	0.42	3.10
Maximum	12,690	7.30	24.90

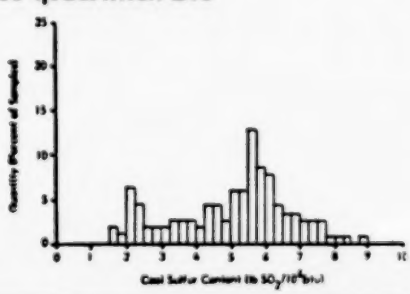
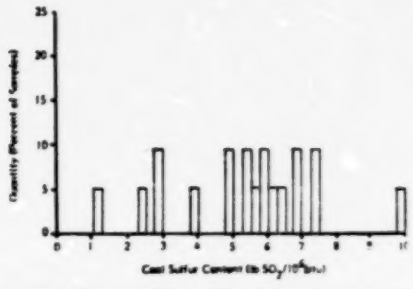


Figure 4.3-2. Indiana Coal Washability Data Sheet

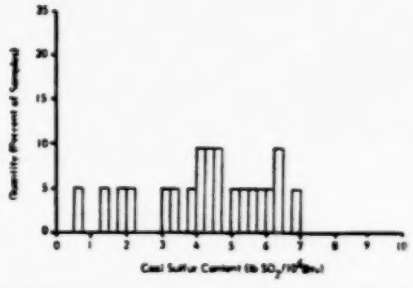
Raw Coal: 21 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,546	3.67	11.89
Std. Dev.	531	1.39	3.46
Minimum	11,598	0.67	6.37
Maximum	13,452	7.17	19.57



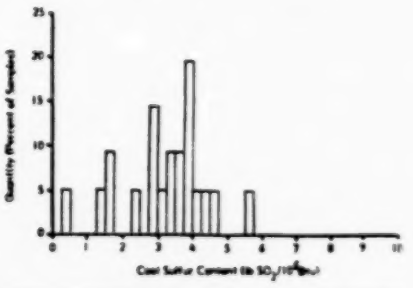
PCC I: 1-1/2 in., 1.6 sp. gr., 21 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,022	2.80	8.54
Std. Dev.	294	1.11	1.67
Minimum	12,255	0.36	5.40
Maximum	13,598	4.33	13.70



PCC II: 3/8 in., 1.3 sp. gr., 21 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,637	2.19	4.25
Std. Dev.	138	0.82	0.62
Minimum	13,391	0.32	3.20
Maximum	13,900	3.85	5.40



Emission Reduction vs. Energy Recovery:

	Emission Reduction (%)		Btu Recovery (%)	
	PCC I	PCC II	PCC I	PCC II
Mean	26.4	43.1	96.4	56.6
Std. Dev.	14.4	14.2	2.2	13.2
Minimum	5.0	15.0	91.7	28.4
Maximum	49.0	64.0	99.1	78.7

Indiana Coal Seams

Springfield (No. 5) Coal. No. 5 coal is the most widely mined in Indiana and has been correlated with Illinois No. 5 and Kentucky No. 9. These coals represent the second largest coal-producing bed in the United States.[1] The seam ranges in minable thickness from four to seven feet throughout much of southwestern Indiana. Primary crushing and mechanical cleaning are effective in removing its free impurities and partings. Springfield coal is free burning, with an ash of medium density, and is suitable for use in electric generating plants and industrial installations.[3]

Hymera (No. 6) Coal. This coal has been correlated with the Illinois No. 6 and Kentucky No. 11 coals and persists in a minable thickness of between four and eight feet throughout southwestern Indiana. In the northern and eastern parts of the field, the coal contains two thin (about one-inch) clay bands in the upper half of the bed. In some locations these bands increase in thickness, eliminating almost all of the upper half of the seam. Pyrite is rather prevalent in this coal but is easily removed by mechanical cleaning. The No. 6 coal lies just below the No. 7 coal, and most mines operating on these coals remove both where possible. Together the No. 6 and No. 7 coals represent about one-half of Indiana's production.[3]

Danville (No. 7) Coal. This coal also persists throughout much of southwestern Indiana, in a minable thickness of between two and six feet. It is low in ash, medium to high in sulfur, and contains few clay partings. It is usually cleaned prior to use for domestic, industrial, and electric generating purposes.[3]

Survant (No. 4) Coal. The Survant coal persists throughout the Indiana coal fields in two benches, each about two feet thick. The upper bench has a semi-blocky nature and produces good lump coal for domestic and steam uses. The lower bench is more friable and produces more fines, but it offers a good assortment of the smaller sizes for both domestic and industrial use. The coal from both benches is relatively low in sulfur and ash and is often used with little or no processing.[3]

Seelyville (No. 3) Coal. This coal, present in most of Indiana's coal-producing counties, averages about six feet in thickness with a maximum thickness of about eight feet. As a high-sulfur coal of medium to high ash content, it requires mechanical cleaning prior to use.[3]

Minshall Coal. The Minshall coal is currently being mined only in Spencer and Daviess counties, where it is called the Buffaloville coal. This coal bed ranges in character from a block or semi-blocky coal to the usual brightly banded, cubic-cleavage type of bituminous coal more common in Indiana. When of a blocky nature, this bed is somewhat higher in sulfur and ash content than the true block coals. The Minshall coal is free burning and is used for both industrial and domestic purposes.[7]

Estimates of Indiana Coal Available to Meet Various SO_2 Emission Regulations

Figure 4.3-3 shows the percentage of projected 1985 Indiana coal production excluding metallurgical coal able to meet various emission standards before cleaning, after cleaning at each of three levels, and when used in conjunction with an FGD system. Indiana coal, like coal from other interior basin states, is high in sulfur and only one-half of it can be used to meet a 5 lb $SO_2/10^6$ Btu emission standard without cleaning. Physical cleaning at 1½ inch, 1.6 sp. gr. can be used to bring one-half of the Indiana coal into compliance with a 3.5 lb $SO_2/10^6$ Btu emission limit while chemical cleaning by a hypothetical process that removes 95 percent of the pyritic and 20 percent of the organic sulfur can bring one-half of the Indiana coal into compliance with a 2 lb $SO_2/10^6$ Btu limit.

Figure 4.3-4 shows the percentage of the projected 1985 Indiana coal production excluding metallurgical coal able, when physically cleaned, to meet a standard stipulating both an SO_2 emission ceiling and a percentage SO_2 reduction. (The circled number next to each curve shows the value of the emission ceiling in lb $SO_2/10^6$ Btu.) The curves in this figure show that physical coal cleaning is able to reduce the sulfur content of one-half of the Indiana coal by 10 percent and about one-third of it by 30 percent. Because of the high sulfur content and washability characteristics of Indiana coal, physical cleaning is unable to produce much compliance coal for an emission standard defined by either a high percentage SO_2 removal or a low emission ceiling.

Table 4.3-1 shows the potential SO_2 emissions, percentage SO_2 reduction, and cost of compliance for an SO_2 emission regulation requiring physical cleaning at 1½ inch top size and 1.6 specific gravity of those coals mined in Illinois for utility use in 1979 that had sulfur contents exceeding a specified floor.

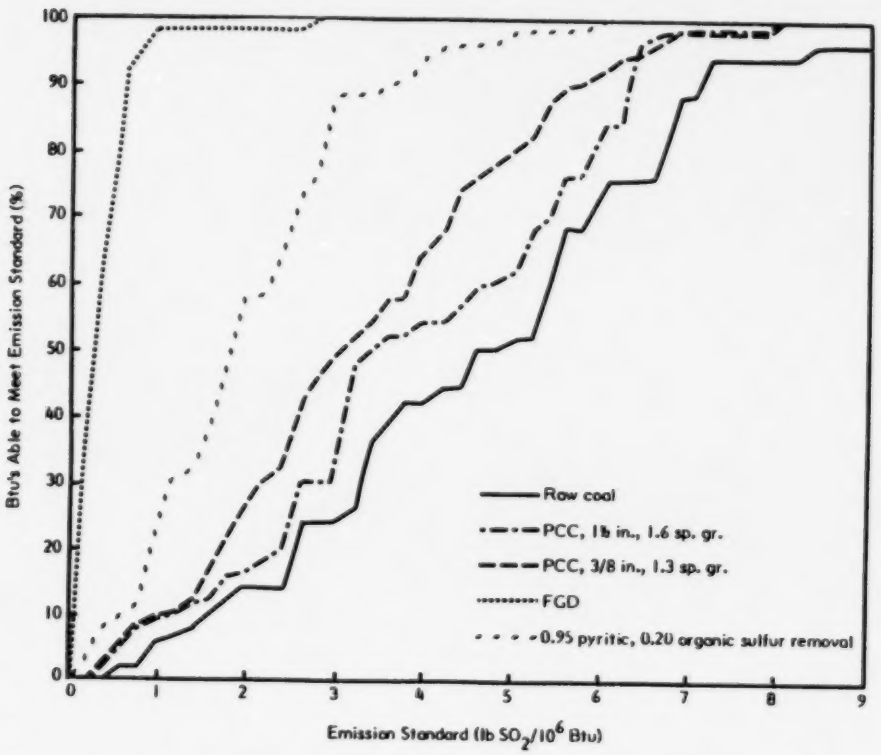


Figure 4.3-3. Percentage of Projected 1985 Indiana Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization

Figure 4.3-4. Percentage of Projected 1985 Indiana Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.

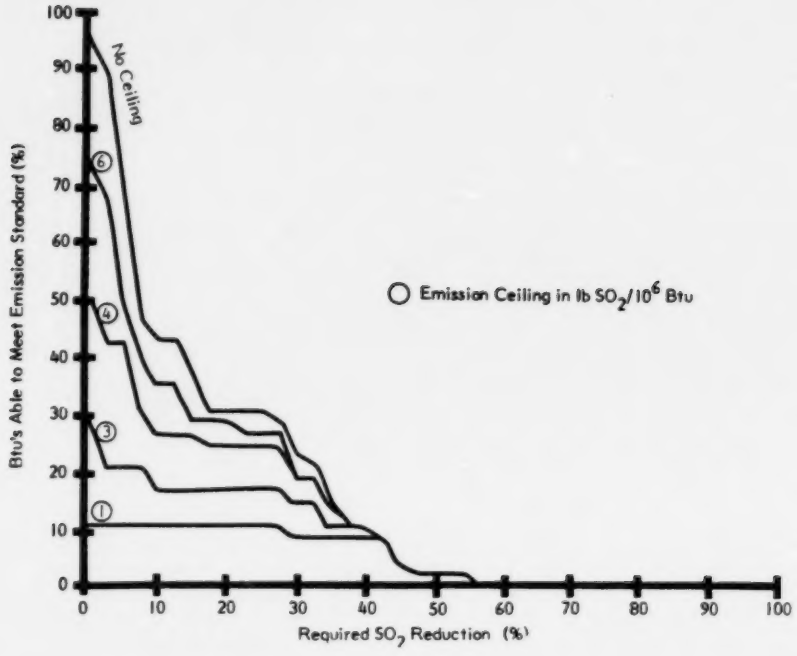


Table 4.3-1. Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Indiana Coals Delivered to Utilities in 1979

Coals to Be Washed*	Quantity to Be Washed (10^3 Tons)	Total SO_2 Emissions after Selective Washing (10^3 Tons)	SO_2 Emission Reduction Achieved by Selective Washing (10^3 Tons)	(%)	Levelized Cost of Washing (10^6 1979$)	Cost-Effectiveness ($/Ton SO_2)
No coals	0	756	0	0	0	–
Coals with SO_2 contents above floor of:						
7 lb/10^6Btu	2,665	691	65	9	11	170
6 lb/10^6Btu	5,132	665	91	12	22	240
5 lb/10^6 Btu	8,384	618	138	18	36	260
4 lb/10^6 Btu	10,557	587	169	22	49	290
All coals	12,484	572	184	24	57	310

* Excluding the 12,839,000 tons of coal actually washed in 1979.

Major Sources of Coal Used by Indiana Utility Plants in 1979

Source states for coal delivered to Indiana utilities in 1979 are listed in Table 4.3-2 along with the quantity and the weighted average sulfur and ash content of the coal from each state. Table 4.3-3 shows the Indiana utility plants that imported the greatest amount of coal in 1979, ranked according to the quantity imported. Following the plant name, the combined units' size and SO_2 limits are shown. In some cases, more than one SO_2 limit applies to various units of a given plant. The remaining columns indicate the quantity imported from each state, the percentage of coal that quantity represented for each plant, and the weighted average sulfur and ash content of the imported coal.

Table 4.3-2. Source State for Coal Used in Indiana Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Indiana	19,700	55	2.94	11.4	5.45
Illinois	6,427	18	2.73	11.3	5.11
Kentucky	4,231	12	3.79	13.0	6.80
Wyoming	1,896	5	0.74	9.2	1.44
Utah	1,334	4	0.60	8.8	1.02
Montana	813	2	0.40	4.3	0.85
Colorado	763	2	0.39	7.4	0.70
Remaining States	436	1	3.56	12.1	6.44
TOTAL	5,598	100	2.70	10.9	4.97

Table 4.3-3. Out-of-State Coal Use by Indiana Plants in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	State of Origin	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
						Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Gibson	2,700	1.2	IL	4,166	74	2.66	11.2	5.01
Tanners Creek	1,009	4.9	KY	1,395	57	3.64	13.4	6.66
Tanners Creek	1,009	4.9	UT	1,017	42	0.56	8.7	0.93
Clifty Creek	1,259	6.0	KY	2,152	56	4.07	13.5	7.23
State Line	508	1.2	MT	813	57	0.40	4.3	0.85
State Line	508	1.2	WY	610	43	0.47	4.7	1.00
Michigan City	600	1.2, 6.0	IL	1,383	73	2.73	12.7	5.11
Schahfer	958	1.2	WY	1,008	92	0.84	11.3	1.59
Mitchell	502	1.2	CO	763	57	0.39	7.4	0.70
Bailly	590	6.0	IL	614	60	3.09	10.0	5.59
Remaining Plants	–	–	–	1,978	10	2.57	10.9	4.62
TOTAL	15,335	–	–	15,899	45	2.40	10.8	4.38

Major Utility Users of Indiana Coal in 1979

Table 4.3-4 lists the states containing utility plants that burned Indiana coal in 1979. Also listed are the Indiana coal quantities received, the percentage of coal use these quantities represented for each state, and the weighted average coal properties. The largest Indiana users of Indiana coal are listed in Table 4.3-5 along with relevant plant information and coal properties.

Table 4.3-4. States Receiving Indiana Coal Deliveries to Utility Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Indiana	19,700	55	2.94	11.0	5.45
Kentucky	1,906	8	2.80	9.7	5.07
Georgia	1,269	7	1.18	9.6	2.16
Illinois	1,080	3	1.98	9.8	3.60
Alabama	440	2	1.74	10.3	3.16
Tennessee	422	2	2.12	9.6	3.87
Wisconsin	289	2	4.17	10.1	7.44
Iowa	83	1	3.19	9.9	5.66
Florida	81	1	3.20	10.5	5.54
Missouri	51	<1	1.10	9.0	2.00
Michigan	1	<1	3.95	11.5	7.48
TOTAL	25,323	–	2.78	10.7	5.13

Table 4.3-5. Indiana Utility Plants Receiving Indiana Coal Deliveries in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
					Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Petersburg	1,221	1.2, 6.0	2,986	100	3.15	10.2	5.74
Cayuga	1,008	6.0	2,569	99	2.50	13.2	4.87
Warrick	819	5.2	2,248	100	3.31	10.5	5.99
Wabash River	877	4.0	1,680	100	2.23	10.6	4.10
Stout	656	5.3	1,592	100	1.73	9.3	3.17
Clifty Creek	1,259	6.0	1,313	34	3.85	12.9	7.39
Gibson	2,700	1.2	1,246	22	3.37	11.0	6.16
Culley	397	5.2	1,046	100	3.33	11.2	6.19
Breed	390	6.0	959	100	3.74	9.6	6.76
Ratts	238	6.0	760	100	3.44	14.2	6.65
Remaining Plants	–	–	3,301	49	2.80	10.2	5.10
TOTAL	15,335	–	19,700	55	2.94	11.0	5.45

4.4 KENTUCKY

General Information

Kentucky has two coal fields; one in eastern Kentucky in the Appalachian coal region and one in western Kentucky in the Eastern Interior coal region. In 1977, Kentucky was the largest coal producing state, with a total production of over 146 million tons. Eastern Kentucky produced 38 million tons of coal from underground mines and 56 million tons from surface mines in 1977 while western Kentucky produced 23 million tons from underground mines and 29 million tons from surface mines. About 14 million tons of eastern Kentucky coal and less than 1 million tons of western Kentucky coal were used as metallurgical coal for producing coke.[1]

About 84 percent of eastern Kentucky coal was shipped by rail or water and 14 percent by truck in 1977, while about 79 percent of western Kentucky coal was shipped by rail or water, 15 percent was shipped by truck, and 5 percent was used in minemouth generating plants.[1]

Pertinent facts regarding eastern Kentucky and western Kentucky coal properties are listed in Figures 4.4-1 and 4.4-2, respectively. The coal properties, taken from the coal data bases described in Section 3, are specified on a moisture-free basis for the reserves and production data bases and on an as-delivered basis for the deliveries-to-utilities data base.

Coal Employment and Production in 1977

County	Production (10^3 Tons)			Value (10^6 $)**	Number of Employees (Monthly Average)**
	Underground*	Surface*	Total*		
Pike	13,973	4,168	18,141	444	8,674
Muhlenburg	4,734	12,452	17,186	253	3,663
Hopkins	5,215	5,150	10,365	194	2,286
Ohio	3,104	7,213	10,317	166	2,768
Harlan	7,497	1,892	9,389	250	4,747
Martin	2,763	6,487	9,250	179	4,746
Perry	2,113	6,678	8,791	177	3,773
Union	7,319	0	7,319	151	2,428
Others	14,954	40,550	55,504	1,114	23,657
TOTAL	61,672	84,590	146,262	2,928	56,742

* Source: Reference 1.

** Source: Reference 6.

Coal Washing in 1977

Eastern Kentucky coals are generally low to medium in sulfur content; the medium-sulfur coals have a substantial amount of pyritic sulfur, which can be removed by physical coal cleaning to produce low-sulfur coal. In 1977, 50 cleaning plants were processing 29 percent of the eastern Kentucky coal.[1] Western Kentucky coals are high in both total and pyritic sulfur and yield medium-sulfur coal when physically cleaned. In 1977, 14 cleaning plants were processing 37 percent of western Kentucky coal.[1] The level to which these coals were cleaned is unknown.

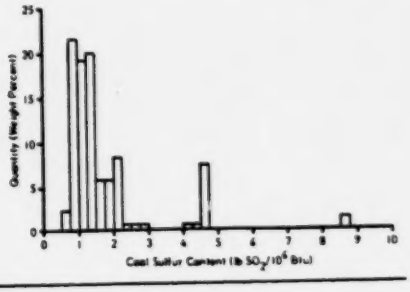
Coal Washability Data

Pertinent facts regarding the washability of eastern and western Kentucky coals, taken from the washability data base described in Section 3, are listed here in Figures 4.4-3 and 4.4-4, respectively. The top portion of the figures provides information regarding the coal properties on a moisture-free basis before and after physical cleaning. Two levels of cleaning, PCC I and PCC II, are analyzed. The bottom portion of the figures summarizes the potential SO_2 emission reduction and energy recovery characteristics of the coals in the washability data base at the two levels of cleaning.

Figure 4.4-1. Eastern Kentucky Coal Properties Fact Sheet

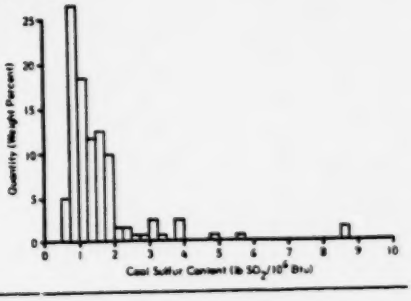
Reserves: 12,889 million tons, 335 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,542	1.23	8.86
Std. Dev.	950	0.92	5.55
Minimum	11,120	0.20	0.90
Maximum	15,130	5.40	23.50



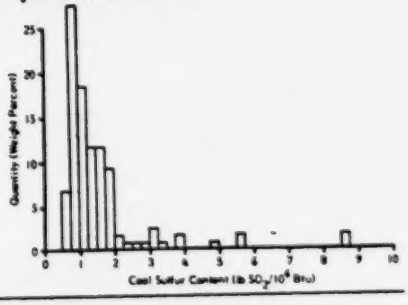
1976 Production: 85.1 million tons, 2.33 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,688	1.13	7.59
Std. Dev.	712	0.82	2.44
Minimum	11,120	0.30	2.10
Maximum	14,760	5.20	17.30



Projected 1985 Production: 106.2 million tons, 2.77 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,659	1.10	7.76
Std. Dev.	721	0.81	2.52
Minimum	11,120	0.30	2.10
Maximum	14,760	5.20	17.30



1979 Deliveries to Utilities: 68.61 million tons, 1.65 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,020	1.14	11.40
Std. Dev.	838	0.53	2.96
Minimum	8,876	0.10	0.80
Maximum	13,783	5.24	11.40

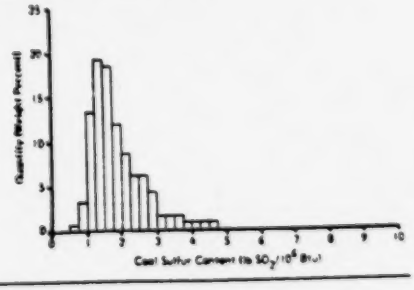
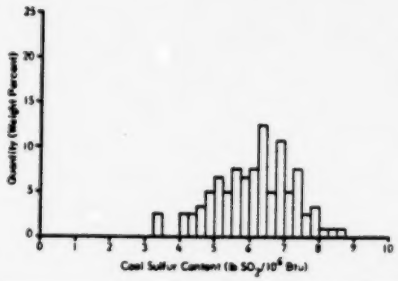


Figure 4.4-2. Western Kentucky Coal Properties Fact Sheet

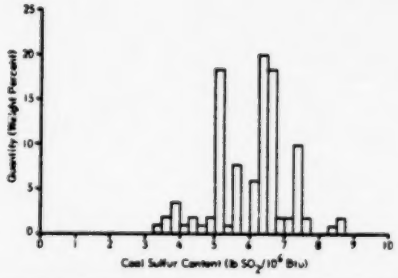
Reserves: 12,602 million tons, 303 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,748	3.86	11.74
Std. Dev.	595	0.63	3.50
Minimum	8,698	0.90	1.60
Maximum	14,410	6.60	37.60



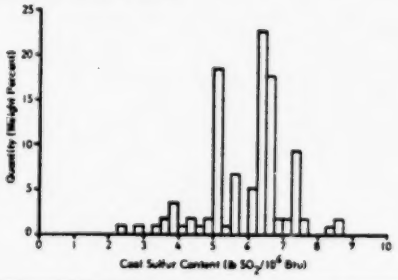
1976 Production: 53.5 million tons, 1.37 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,795	3.85	11.19
Std. Dev.	545	0.63	2.37
Minimum	11,486	1.20	5.80
Maximum	14,310	6.20	17.20



Projected 1985 Production: 58.7 million tons, 1.40 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,805	3.84	11.12
Std. Dev.	537	0.65	2.39
Minimum	11,486	1.20	5.80
Maximum	14,310	6.20	17.20



1979 Deliveries to Utilities: 38.13 million tons, 0.85 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	11,194	3.40	12.83
Std. Dev.	588	0.73	3.41
Minimum	9,409	0.45	3.30
Maximum	13,615	6.28	23.10

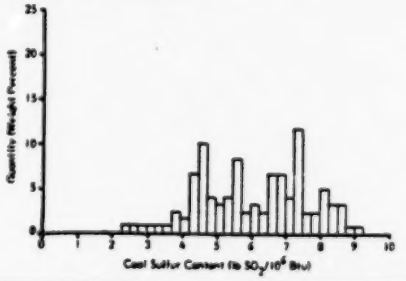
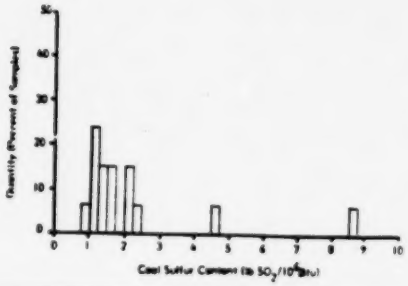


Figure 4.4-3. Eastern Kentucky Coal Washability Data Sheet

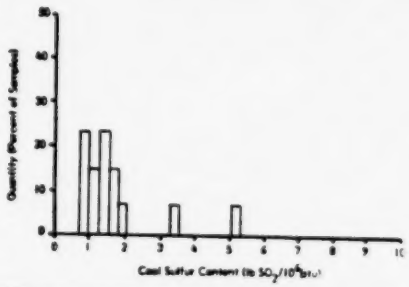
Raw Coal: 13 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,986	1.44	11.48
Std. Dev.	1,163	1.21	7.44
Minimum	11,120	0.56	2.13
Maximum	14,366	4.88	23.47



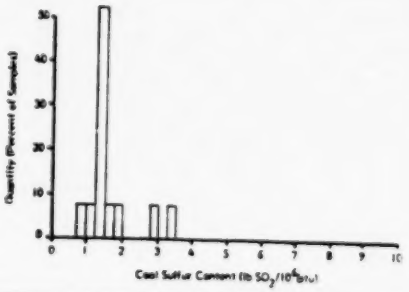
PCC I: 1-1/2 in., 1.6 sp. gr., 13 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,862	1.20	5.53
Std. Dev.	619	0.78	3.55
Minimum	12,676	0.59	1.50
Maximum	14,474	3.32	12.70



PCC II: 3/8 in., 1.3 sp. gr., 13 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,319	1.02	2.42
Std. Dev.	294	0.55	1.11
Minimum	13,846	0.48	1.20
Maximum	14,725	2.42	4.60



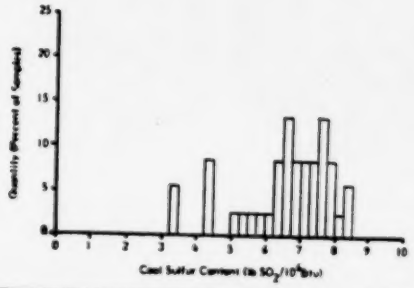
Emission Reduction vs. Energy Recovery:

	Emission Reduction (%)		Btu Recovery (%)	
	PCC I	PCC II	PCC I	PCC II
Mean	15.9	25.6	94.7	64.2
Std. Dev.	12.1	17.2	4.6	23.7
Minimum	2.0	3.0	83.6	21.7
Maximum	39.0	61.0	99.7	94.9

Figure 4.4-4. Western Kentucky Coal Washability Data Sheet

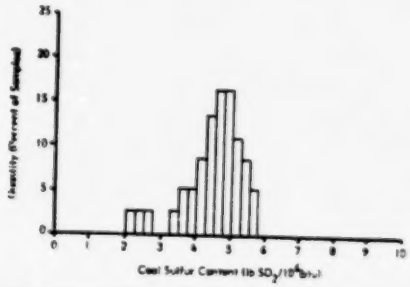
Raw Coal: 37 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,339	4.05	13.81
Std. Dev.	864	0.71	5.52
Minimum	8,698	2.17	5.17
Maximum	13,676	5.02	37.63



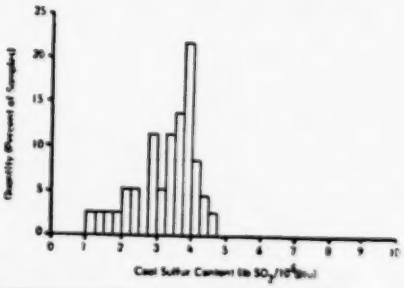
PCC I: 1-1/2 in., 1.6 sp. gr., 37 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,242	2.96	7.49
Std. Dev.	360	0.55	2.10
Minimum	12,555	1.47	3.10
Maximum	13,926	3.75	12.20



PCC II: 3/8 in., 1.3 sp. gr., 37 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,826	2.26	3.41
Std. Dev.	182	0.61	0.76
Minimum	13,522	0.82	1.60
Maximum	14,216	3.32	4.90



Emission Reduction vs. Energy Recovery:

	Emission Reduction (%)		Btu Recovery (%)	
	PCC I	PCC II	PCC I	PCC II
Mean	31.5	49.6	95.2	55.6
Std. Dev.	11.9	13.2	2.6	16.5
Minimum	3.0	15.0	84.7	26.9
Maximum	50.0	77.0	99.6	86.5

Eastern Kentucky Coal Seams

Upper Elkhorn No. 3 Coal. This coal bed is the most important one in the eastern Kentucky coal field and the seventh largest producing bed in the United States.[1] It is known by many names in the various mining districts of eastern Kentucky, including Cedar Grove, Darby, Jellico, Mason, Millers Creek, Mingo, Straight Creek, and Thacker. The Upper Elkhorn No. 3 coal is present in one or more benches of up to six feet in thickness with one or more partings that occasionally reach a thickness of nearly one foot.[3]

Fire Clay Coal. This coal bed, widespread in eastern Kentucky, is also known by many names, including Dean, Hazard No. 4, Poplar Lick, and Wallins. In the Big Sandy reserve district the coal generally consists of several beds with bone, flint-clay, or shale partings. Although its thickness in the Big Sandy district varies greatly, large areas are over two feet thick. In the Hazard reserve district, the Fire Clay coal is known commercially as Hazard No. 4 and generally occurs as a bright-banded, three-foot-thick single seam with persistent flint-clay partings. In other reserve districts this coal is usually about three to four feet thick with partings up to six inches thick.[3]

Hazard 5a Coal. This coal bed, the nation's eighth largest producer in 1977, is mined in eastern Kentucky, West Virginia, and Virginia.[1] In the Hazard reserve district it is also known as Leatherwood and Prater coal. It has a variable thickness, which in small areas may reach five feet. Some partings of up to three inches thick are present, but they are not persistent over large areas.[3]

Lower Elkhorn Coal. This coal is mined in eastern Kentucky, West Virginia, Virginia, and Tennessee. In 1977 it was the largest producing bed in the United States.[1] Lower Elkhorn coal, known also as Freeburn, Imboden, Pond Creek, and Warfield, is mined in many of the eastern Kentucky reserve districts. In the Hazard district it ranges up to three feet in thickness and in some areas contains one-foot-thick partings. In the Big Sandy reserve district it is reported to be as much as five feet thick with 10-inch-thick partings.[3]

Western Kentucky Coal Seams

Herrin (No. 11) Coal. The Herrin (No. 11) coal bed is the third largest producing bed in the United States and is mined in western Kentucky, Indiana, Illinois, and Missouri.[1] Kentucky No. 11 has been correlated with Indiana No. 6 and Illinois No. 6. The No. 11 bed presents a pattern of thick coal (up to seven feet) in the southern outcrop region of Hopkins, Ohio, and Muhlenberg counties, with thinning trends to the northeast. It is characterized by a shale parting of one to three inches in the lower part of the bed.[3,7]

Mulford (No. 9) Coal. The No. 9 coal is the most persistent and consistent bed in the western Kentucky field and has been correlated with Illinois No. 5 and Indiana No. 5.[3] These coals represent the second largest coal-producing bed in the United States.[1] The No. 9 coal is found continuously within its outcrop limits, in thicknesses of up to six feet. In an area of central Webster County the bed thins abruptly, while in southern Hopkins County it is generally more than four feet thick.[3,7]

Estimates of Eastern Kentucky Coal Available to Meet Various SO_2 Emission Regulations

Figure 4.4-5 shows the percentage of projected 1985 eastern Kentucky coal production excluding metallurgical coal able to meet various emission standards before cleaning, after cleaning at each of three levels, and when used in conjunction with an FGD system. Coal from eastern Kentucky is low in sulfur and is able to comply with low SO_2 emission limits without physical cleaning. Cleaning does, however, substantially increase the quantity of eastern Kentucky coal able to comply with a low SO_2 emission limit.

Figure 4.4-6 shows the percentage of the projected 1985 eastern Kentucky coal production excluding metallurgical coal able, when physically cleaned, to meet a standard stipulating both an SO_2 emission ceiling and a percentage SO_2 reduction. (The circled number next to each curve shows the value of the emission ceiling in lb $SO_2/10^6$ Btu.) The curves in this figure show that almost one-half of eastern Kentucky coal can, by physical cleaning, comply with a 20 percent SO_2 reduction requirement and that about one-half can comply with an emission standard defined by a 20 percent SO_2 reduction and a 2 lb/10^6 Btu ceiling.

Table 4.4-1 shows the potential SO_2 emissions, percentage SO_2 reduction, and cost of compliance for an SO_2 emission regulation requiring physical cleaning at 1½ inch top size and 1.6 specific gravity of those coals mined in eastern Ketucky for utility use in 1979 that had sulfur contents exceeding a specified floor.

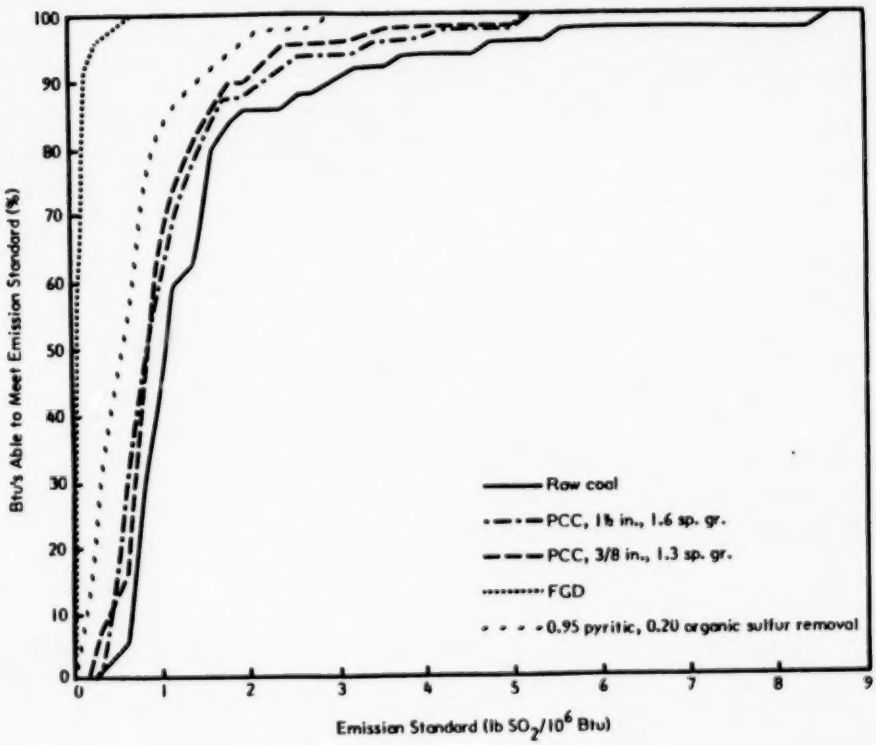


Figure 4.4-5. Percentage of Projected 1985 Eastern Kentucky Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization

Figure 4.A-6. Percentage of Projected 1985 Eastern Kentucky Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1¼", 1.6 sp. gr.

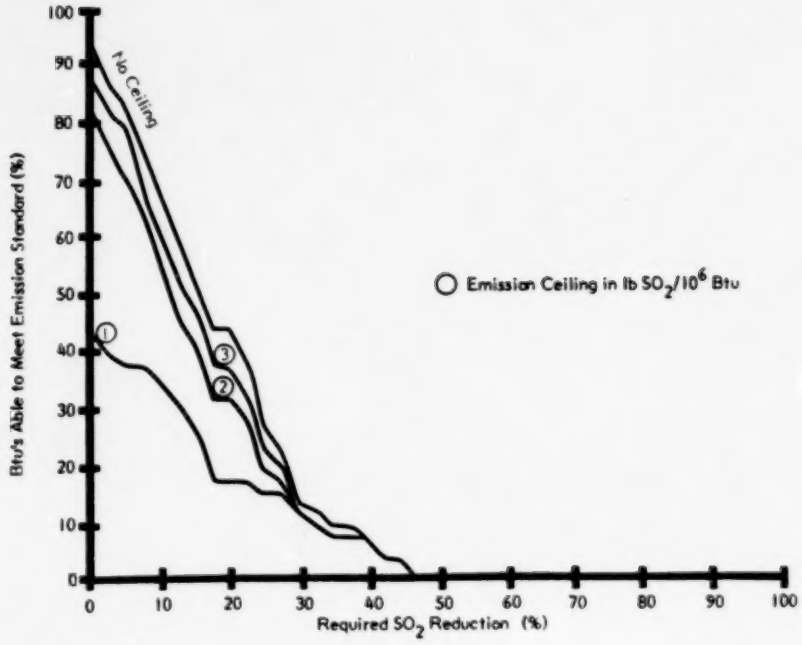


Table 4.A-1. Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Eastern Kentucky Coals Delivered to Utilities in 1979

Coals to Be Washed*	Quantity to Be Washed (10^3 Tons)	Total SO_2 Emissions after Selective Washing (10^3 Tons)	SO_2 Emission Reduction Achieved by Selective Washing		Levelized Cost of Washing (10^6 1979$)	Cost-Effectiveness ($/Ton SO_2)
			(10^3 Tons)	(%)		
No coals	0	1,310	0	0	0	–
Coals with SO_2 contents above floor of:						
4 lb/10^6 Btu	1,965	1,277	33	3	15	460
3 lb/10^6 Btu	5,214	1,245	65	5	45	690
2 lb/10^6 Btu	20,510	1,164	147	11	202	1,370
1 lb/10^6 Btu	53,074	1,059	251	19	529	2,110
All coals	54,898	1,055	255	19	551	2,160

* Excluding the 13,702,000 tons of coal actually washed in 1979.

Estimates of Western Kentucky Coal Available to Meet Various SO_2 Emission Regulations

Figure 4.4-7 shows the percentage of projected 1985 western Kentucky production excluding metallurgical coal able to meet various emission standards before cleaning, after cleaning at each of three levels, and when used in conjunction with an FGD system. Coal from western Kentucky is high in sulfur and is generally unable to comply with SO_2 emission limits lower than 5 to 7 lb $SO_2/10^6$ Btu. Physical cleaning of this coal substantially increases the quantity able to comply with SO_2 emission limits in the 4 to 5 lb/10^6 Btu range while chemical cleaning by a hypothetical process that removes 95 percent of the pyritic and 20 percent of the organic sulfur would allow about one-half of the coal to comply with a 2.5 lb $SO_2/10^6$ Btu emission limit.

Figure 4.4-8 shows the percentage of the projected 1985 western Kentucky coal production excluding metallurgical coal able, when physically cleaned, to meet a standard stipulating both an SO_2 emission ceiling and a percentage SO_2 reduction. (The circled number next to each curve shows the value of the emission ceiling in lb $SO_2/10^6$ Btu.) The curves in this figure show that almost all western Kentucky coal can comply with a 20 percent SO_2 reduction requirement of physically cleaned but cannot comply with a relatively low emission ceiling combined with a percentage reduction SO_2 standard.

Table 4.4-2 shows the potential SO_2 emissions, percentage SO_2 reduction, and cost of compliance for an SO_2 emission regulation requiring physical cleaning at 1½ inch top size and 1.6 specific gravity of those coals mined in western Kentucky for utility use in 1979 that had sulfur contents exceeding a specified floor.

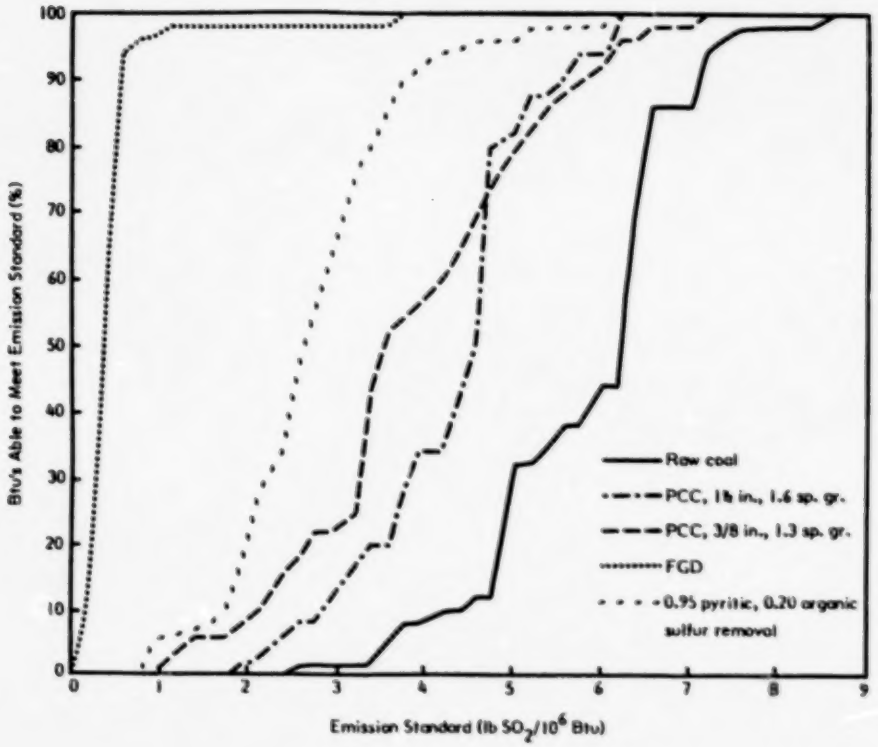


Figure 4.4-7. Percentage of Projected 1985 Western Kentucky Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization

Figure 4.A-8. Percentage of Projected 1985 Western Kentucky Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.

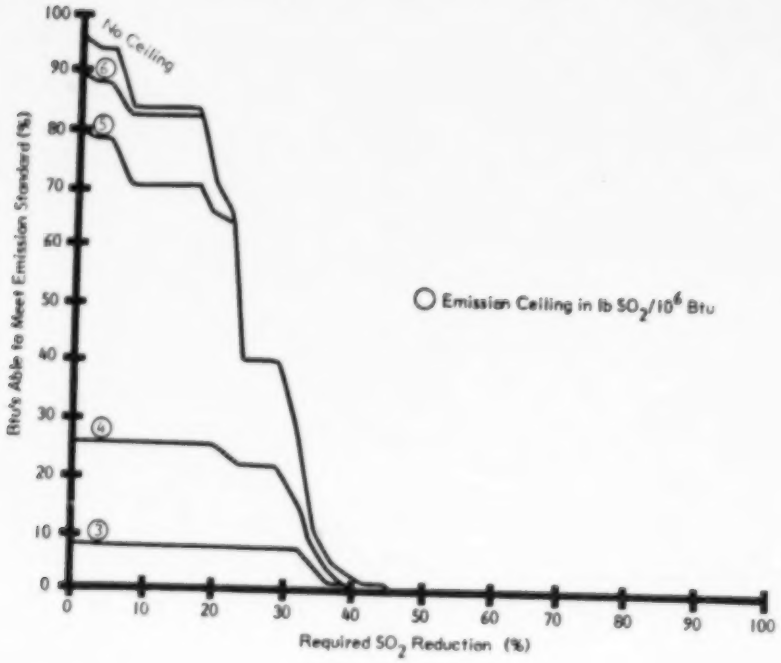


Table 4.A-2. Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Western Kentucky Coals Delivered to Utilities in 1979

Coals to Be Washed*	Quantity to Be Washed (10^3 Tons)	Total SO_2 Emissions after Selective Washing (10^3 Tons)	SO_2 Emission Reduction Achieved by Selective Washing		Levelized Cost of Washing (10^6 1979$)	Cost-Effectiveness ($/Ton SO_2)
			(10^3 Tons)	(%)		
No coals	0	1,896	0	0	0	–
Coals with SO_2 contents above floor of:						
7 lb/10^6Btu	12,997	1,538	358	19	88	250
6 lb/10^6Btu	18,998	1,432	464	24	122	260
5 lb/10^6 Btu	21,808	1,393	503	27	139	280
4 lb/10^6 Btu	23,865	1,364	531	28	152	290
All coals	26,076	1,343	553	29	169	310

* Excluding the 12,051,000 tons of coal actually washed in 1979.

Major Sources of Coal Used by Kentucky Utility Plants in 1979

Source states for coal delivered to Kentucky utilities in 1979 are listed in Table 4.4-3 along with the quantity and the weighted average sulfur and ash content of the coal from each state. Table 4.4-4 shows the Kentucky utility plants that imported the greatest amount of coal in 1979, ranked according to the quantity imported. Following the plant name, the combined units' size and SO_2 limits are shown. In some cases, more than one SO_2 limit applies to various units of a given plant. The remaining columns indicate the quantity imported from each state, the percentage of coal that quantity represented for each plant, and the weighted average sulfur and ash content of the imported coal.

Table 4.4-3. Source State for Coal Used in Kentucky Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Kentucky	21,056	85	2.91	13.4	5.32
Indiana	1,906	8	2.80	9.7	5.07
Virginia	532	2	0.61	6.4	0.90
Illinois	504	2	3.22	16.8	6.18
West Virginia	388	2	0.81	11.7	1.33
Tennessee	175	< 1	1.80	15.0	3.09
Remaining States	172	< 1	2.42	15.4	4.31
TOTAL	24,732	100	2.81	13.1	5.14

Table 4.4-4. Out-of-State Coal Use by Kentucky Plants in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	State of Origin	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
						Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Shawnee	1,530	1.2	VA	532	15	0.61	6.4	0.90
Shawnee	1,530	1.2	IL	504	14	3.22	16.8	6.18
Shawnee	1,530	1.2	WV	292	8	0.69	10.8	1.08
Ghent	1,047	1.2, 6.0	IN	1,205	50	3.08	9.9	5.61
Coleman	450	5.3	IN	192	12	2.39	9.6	4.27
Coleman	450	5.3	OH	171	10	2.42	15.4	4.31
Brown	700	6.0	TN	175	12	1.81	15.0	3.09
Big Sandy	1,060	6.0	WV	94	4	1.16	14.5	2.06
Mill Creek	1,081	1.2	IN	44	2	3.63	11.4	6.73
Remaining Plants	–	–	–	468	6	2.17	9.0	3.84
TOTAL	11,799	–	–	3,677	15	2.24	10.9	4.13

Major Utility Users of Kentucky Coal in 1979

Table 4.4-5 lists the states containing utility plants that burned Kentucky coal in 1979. Also listed are the Kentucky coal quantities received, the percentage of coal use these quantities represented for each state, and the weighted average coal properties. The largest Kentucky users of Kentucky coal are listed in Table 4.4-6 along with relevant plant information and coal properties.

Table 4.4-5. States Receiving Kentucky Coal Deliveries to Utility Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Kentucky	21,056	85	2.91	13.4	5.32
Tennessee	15,828	68	2.33	13.1	4.14
Ohio	12,106	23	1.25	13.2	2.21
Georgia	11,890	62	1.76	11.1	2.96
North Carolina	10,918	52	0.94	10.7	1.55
Michigan	9,150	38	0.93	9.4	1.51
South Carolina	4,947	84	1.32	10.6	2.13
Indiana	4,231	12	3.79	13.0	6.80
Florida	3,733	63	2.22	9.8	3.79
Alabama	3,415	19	2.55	12.8	4.40
West Virginia	2,703	10	0.96	12.2	1.63
Remaining 10 States	6,760	4	1.92	9.9	3.26
TOTAL	106,738	–	1.95	11.9	3.42

Table 4.4-6. Kentucky Utility Plants Receiving Kentucky Coal Deliveries in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
					Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Paradise	2,377	0.9, 5.2	5,407	100	4.35	17.1	8.26
Mill Creek	1,081	1.2	2,191	98	3.53	14.3	6.48
Shawnee	1,530	1.2	2,191	62	2.22	10.5	3.83
Big Sandy	1,060	6.0	2,039	96	1.19	13.5	2.11
Cane Run	989	1.2	1,634	100	3.35	12.4	6.10
Brown	700	6.0	1,339	88	2.51	13.2	4.25
Coleman	450	5.3	1,277	78	2.81	11.9	5.05
Ghent	1,047	1.2, 6.0	1,216	50	0.71	9.3	1.16
Elmer Smith	399	6.0	832	95	2.90	9.6	5.22
Cooper	354	3.3	725	100	1.48	10.0	2.43
Remaining Plants	–	–	2,205	88	2.67	13.0	4.94
TOTAL	11,799	–	21,056	85	2.91	13.4	5.32

4.5 OHIO

General Information

The Ohio coal fields are located in the southeastern quarter of Ohio and include a 25-county area. In 1977, Ohio was the fifth largest coal-producing state behind Kentucky, West Virginia, Pennsylvania, and Illinois. Surface mining produced 33 million tons in Ohio in 1977, while underground mining produced 14 million tons. None of the Ohio coal produced in 1977 was used as metallurgical coal for the production of coke.[1]

One-half of the Ohio coal in 1977 was shipped by rail or water, 35 percent was shipped by truck, and 15 percent was used by minemouth generating plants.[1]

Pertinent facts regarding Ohio coal properties are listed in Figure 4.5-1. The coal properties, taken from the coal data bases described in Section 3, are specified on a moisture-free basis for the reserves and production data bases and on an as-delivered basis for the deliveries-to-utilities data base.

Employment and Production in 1977

County	Production (10^3 Tons)			Value (10^6 $)**	Number of Employees (Monthly Average)**
	Underground*	Surface*	Total*		
Belmont	4,851	6,936	11,787	231	3,874
Harrison	3,029	3,096	6,125	138	2,411
Muskingum	153	5,468	5,621	88	1,383
Jefferson	368	3,806	4,174	69	837
Vinton	642	1,769	2,411	37	776
Perry	1,589	761	2,350	23	733
Coshocton	307	1,701	2,008	35	576
Tuscarawas	21	1,785	1,807	30	298
Others	3,216	8,420	11,635	197	4,314
TOTAL	14,176	33,742	47,918	848	15,202

* Source: Reference 1.

** Source: Reference 9.

Coal Washing in 1977

Because of their high pyritic sulfur content, Ohio coals are very amenable to sulfur reduction by physical coal cleaning methods. The 14 coal cleaning plants reported as operating in Ohio in 1977 processed 32 percent of the coal and removed an average of 29 percent by weight of the coal processed.[9] Most of the coal from the Pittsburgh seam and nearly half of the Middle Kittanning coal was cleaned, resulting in an estimated SO_2 reduction of 30 to 40 percent.

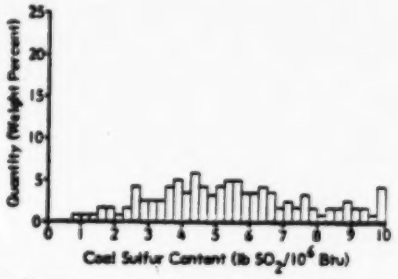
Coal Washability Data

Pertinent facts regarding the washability of Ohio coals, taken from the washability data base described in Section 3, are listed here in Figure 4.5-2. The top portion of the figure provides information regarding the coal properties on a moisture-free basis before and after physical cleaning. Two levels of cleaning, PCC I and PCC II, are analyzed. The bottom portion of this figure summarizes the potential SO_2 emission reduction and energy recovery characteristics of the coals in the washability data base at the two levels of cleaning.

Figure 4.5-1. Ohio Coal Properties Fact Sheet

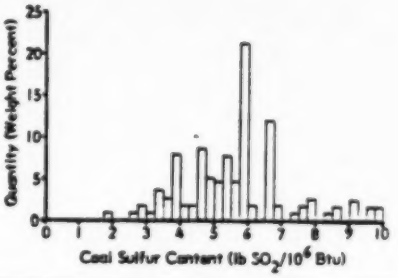
Reserves: 21,055 million tons, 509 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,780	3.45	11.78
Std. Dev.	907	1.40	5.39
Minimum	8,571	0.50	2.20
Maximum	14,256	9.40	37.40



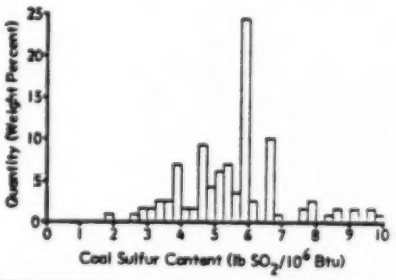
1976 Production: 45.80 million tons, 1.11 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,921	3.62	11.01
Std. Dev.	489	1.02	2.16
Minimum	9.750	0.60	5.20
Maximum	14,230	8.70	23.40



Projected 1985 Production: 54.54 million tons, 1.34 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,937	3.62	10.95
Std. Dev.	481	1.00	2.03
Minimum	9.750	0.60	5.20
Maximum	14,230	8.70	23.40



1979 Deliveries to Utilities: 38.31 million tons, 0.86 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	11,183	3.48	15.00
Std. Dev.	838	0.95	4.12
Minimum	8,564	0.67	3.00
Maximum	14,436	6.58	25.10

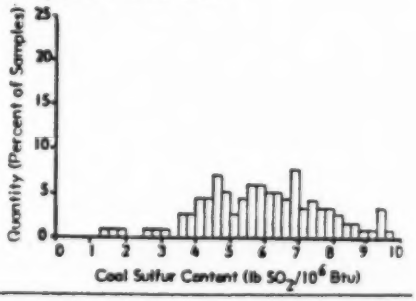
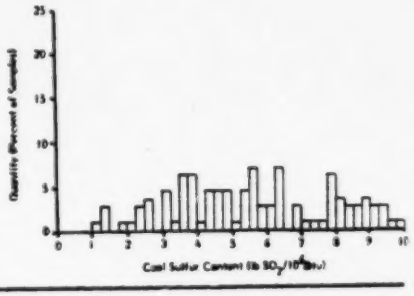


Figure 4.5-2. Ohio Coal Washability Data Sheet

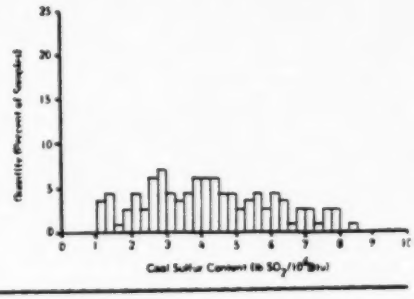
Raw Coal: 90 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,494	3.55	13.61
Std. Dev.	930	1.39	5.56
Minimum	8,571	0.67	3.57
Maximum	14,256	6.55	37.43



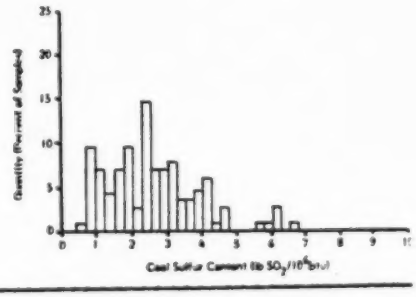
PCC I: 1-1/2 in., 1.6 sp. gr., 90 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,212	2.77	8.65
Std. Dev.	586	1.16	3.08
Minimum	11,689	0.66	3.10
Maximum	14,325	5.46	17.50



PCC II: 3/8 in., 1.3 sp. gr., 90 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,952	1.81	3.56
Std. Dev.	329	0.89	1.01
Minimum	12,871	0.51	1.50
Maximum	14,578	4.26	8.50



Emission Reduction vs. Energy Recovery:

	Emission Reduction (%)		Btu Recovery (%)	
	PCC I	PCC II	PCC I	PCC II
Mean	25.9	53.4	95.2	45.7
Std. Dev.	12.7	13.7	2.9	22.2
Minimum	8.0	16.0	82.4	5.4
Maximum	63.0	81.0	99.6	90.0

Ohio Coal Seams

Pittsburgh Coal. Slightly more than one-quarter of the coal produced in Ohio in 1977 came from this coal bed.[9] The Pittsburgh bed is the largest coal producer in the United States,[1] persisting in minable thickness over more than 5,000 square miles in Pennsylvania, West Virginia, Maryland, and Ohio. Reserves in Ohio are estimated at over 10 billion tons of coal above 31 inches in thickness. In the No. 8 district, the Pittsburgh bed covers about 800 square miles averaging about five feet in thickness. Production is about equally divided between surface and underground mining methods, and about 88 percent of the Pittsburgh coal is washed prior to use. The coal is moderately coking, of firm structure, and used primarily in large utility and industrial pulverized coal boilers.[3]

Middle Kittanning Coal. This coal bed provided slightly less than one-quarter of Ohio's coal in 1977[9] and is an important producing bed also in Pennsylvania and West Virginia. (It is the sixth largest producing bed in the United States.)[1] Conservative estimates indicate well over 7 billion tons, more than 28 inches thick, in Ohio District No. 6. Both surface and underground mining methods are used, and about 44 percent of the coal is washed prior to use. The coal is exceptionally firm and has a low ash content (and often a high ash fusion temperature) along with a very low free-swelling index. It is used extensively in the ceramic and cement industries and for steam generation in stoker-fired boilers.[3]

Meigs Creek Coal. The Meigs Creek seam, which accounted for about 18 percent of Ohio coal production in 1977, is believed to contain the largest easily accessible unmined reserve in the state. The seam is estimated to be of minable thickness over an area of 1,040 square miles and generally lies near the surface, making it suitable for mining by surface methods. Structurally, the Meigs Creek coal varies from a massive bed to a bed broken by one or more partings. The high ash and sulfur content of this coal is largely attributable to closely spaced, paper-thin shaly partings.[3] In 1977, only 8 percent of the coal was washed.[9] Meigs Creek is generally unsuitable for domestic use and is burned primarily in modern pulverized coal-fired boilers.[3]

Clarion Coal. This coal accounted for about 6 percent of Ohio's production in 1977. About 12 percent of it was washed prior to use.[9] The usual structure of the coal consists of three benches separated by two partings of clay. The thickness of the bed in southern Ohio is about 3 feet; and that of coal and partings about 4 feet. The Clarion coal is generally mined by conventional underground methods. When washed, it is highly suitable for steam generation in stoker and pulverized coal boilers.[3]

Lower Kittanning Coal. This coal bed is the fourth largest producing bed in the United States. Mined primarily in Pennsylvania, West Virginia, eastern Kentucky, Ohio, and Maryland,[1] it accounted for about 5 percent of Ohio's 1977 coal production. Only 5 percent of this coal was washed in 1977.[9] Lower Kittanning reserves in Ohio are estimated at over 3 billion tons above 28 inches thick. The coal commonly occurs as a single block without noticeable partings and is mined by both underground and surface methods. It lies just above the state's most valuable and persistent clay bed which is used extensively by large scale ceramic industries for the production of sewer pipe, face brick, stoneware, fireproofing, and refractory ware. Cement plants have found this coal suitable for clinkering the shale and clay used in the manufacture of Portland cement.[3]

Estimates of Ohio Coal Available to Meet Various SO_2 Emission Regulations

Figure 4.5-3 shows the percentage of projected 1985 Ohio coal production excluding metallurgical coal able to meet various emission standards before cleaning, after cleaning at each of three levels, and when used in conjunction with an FGD system. Ohio coal is generally high in sulfur and most of it is unable to comply with SO_2 emission limits lower than about 6 lb/10^6 Btu. Physical cleaning of Ohio coal substantially increases the quantity of coal able to comply with SO_2 emission standards in the 4 to 5 lb/MBtu range and chemical cleaning by a hypothetical process that removes 95 percent of the pyritic and 20 percent of the organic sulfur allow about one-half of the Ohio coal to comply with a 2 lb $SO_2/10^6$ Btu emission limit.

Figure 4.5-4 shows the percentage of the projected 1985 Ohio coal production excluding metallurgical coal able, when physically cleaned, to meet a standard stipulating both an SO_2 emission ceiling and a percentage SO_2 reduction. (The circled number next to each curve shows the value of the emission ceiling in lb $SO_2/10^6$ Btu.) The curves in this figure show that physical cleaning can reduce the sulfur content of most of the Ohio coal by 20 percent and can bring much of the Ohio coal into compliance with a 4 lb $SO_2/10^6$ Btu ceiling combined with a 20 percent SO_2 removal emission regulation.

Table 4.5-1 shows the potential SO_2 emissions, percentage SO_2 reducton, and cost of compliance for an SO_2 emission regulation requiring physical cleaning at 1½ inch top size and 1.6 specific gravity of those coals mined in Ohio for utility use in 1979 that had sulfur contents exceeding a specified floor.

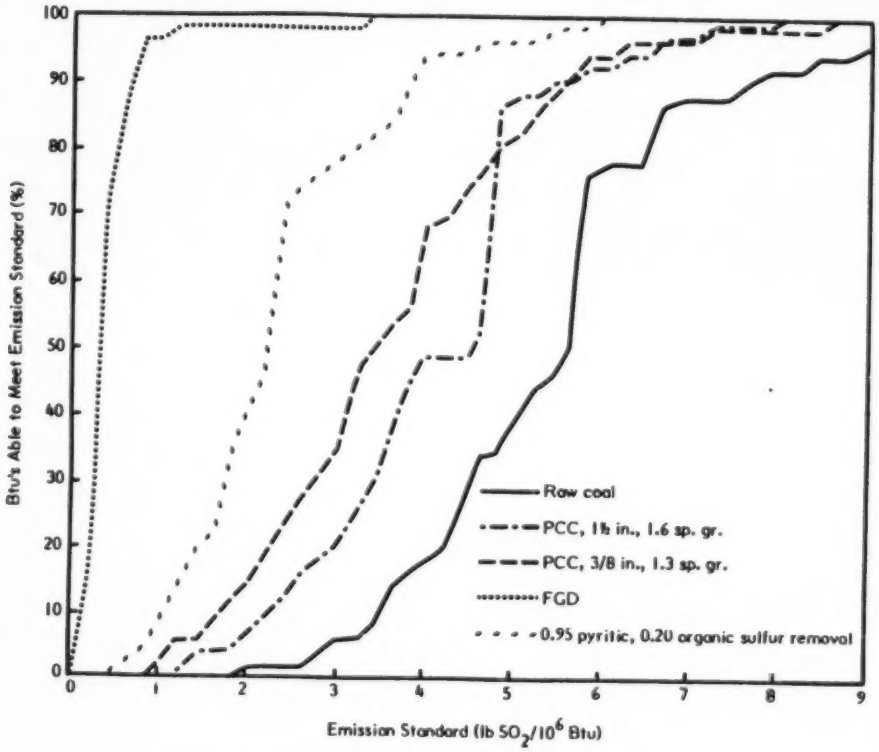


Figure 4.5-3. Percentage of Projected 1985 Ohio Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization

Figure 4.5-4. Percentage of Projected 1985 Ohio Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.

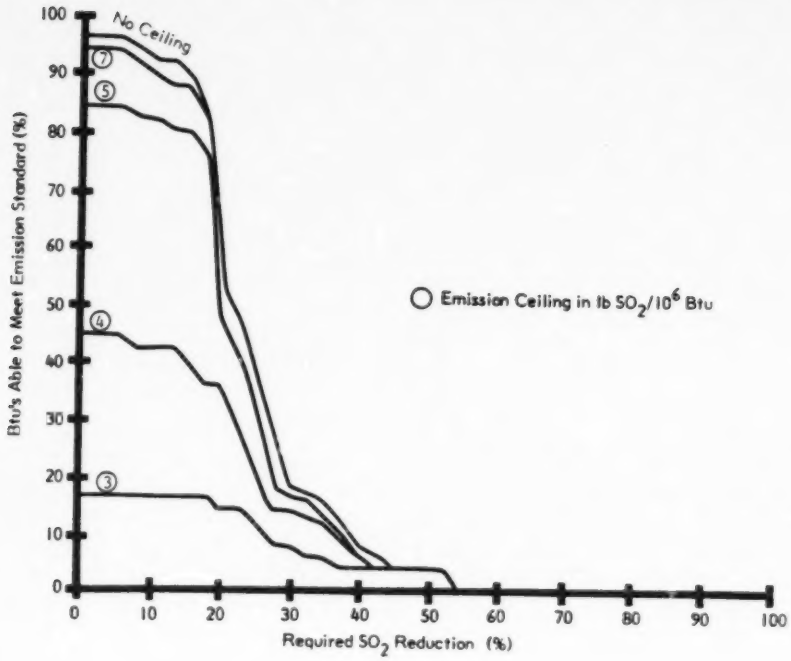


Table 4.5-1. Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Ohio Coals Delivered to Utilities in 1979

Coals to Be Washed*	Quantity to Be Washed (10^3 Tons)	Total SO_2 Emissions after Selective Washing (10^3 Tons)	SO_2 Emission Reduction Achieved by Selective Washing		Levelized Cost of Washing (10^6 1979$)	Cost-Effectiveness ($/Ton SO_2)
			(10^3 Tons)	(%)		
No coals	0	2,479	0	0	0	–
Coals with SO_2 contents above floor of:						
7 lb/10^6Btu	12,353	2,101	378	15	137	360
6 lb/10^6Btu	20,225	1,964	515	21	201	390
5 lb/10^6 Btu	27,063	1,832	647	26	273	420
4 lb/10^6 Btu	31,986	1,757	722	29	302	420
All coals	34,527	1,735	744	30	322	430

* Excluding the 3,787,000 tons of coal actually washed in 1979.

Major Sources of Coal Used by Ohio Utility Plants in 1979

Source states for coal delivered to Ohio utilities in 1979 are listed in Table 4.5-2 along with the quantity and the weighted average sulfur and ash content of the coal from each state. Table 4.5-3 shows the Ohio utility plants that imported the greatest amount of coal in 1979, ranked according to the quantity imported. Following the plant name, the combined units' size and SO_2 limits are shown. In some cases, more than one SO_2 limit applies to various units of a given plant. The remaining columns indicate the quantity imported from each state, the percentage of coal that quantity represented for each plant, and the weighted average sulfur and ash content of the imported coal.

Table 4.5-2. Source State for Coal Used in Ohio Plants

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Ohio	27,561	52	3.70	15.7	6.78
Kentucky	12,106	23	1.25	13.2	2.21
West Virginia	8,129	15	2.06	13.6	3.56
Wyoming	3,649	7	0.50	5.8	1.24
Pennsylvania	1,624	3	3.11	12.9	5.24
Maryland	31	< 1	2.50	14.1	4.22
Utah	0.1	< 1	0.54	11.8	0.98
TOTAL	53,100	100	2.66	14.0	4.82

Table 4.5-3. Out-of-State Coal Use by Ohio Plants

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	State of Origin	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
						Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Stuart	2,334	3.2	KY	5,078	80	1.10	15.0	1.96
Stuart	2,334	3.2	WV	760	12	0.95	14.7	1.67
Gavin	2,600	9.5	WY	3,648	40	0.50	5.8	1.24
Gavin	2,600	9.5	WV	832	9	3.31	17.7	6.21
Miami Fort	1,383	1.2, 1.6 3.3, 5.5	KY	1,816	62	2.21	13.1	3.98
Miami Fort	1,383	1.2, 1.6 3.3, 5.5	WV	704	24	0.73	11.8	1.20
Cardinal	1,186	4.8	WV	1,832	42	1.30	15.0	2.22
Kyger Creek	1,055	8.2	WV	1,796	57	4.16	14.0	7.16
Beckjord	1,165	2.0	KY	1,319	52	1.69	14.8	3.07
Bayshore	630	1.2	WV	726	54	0.91	8.5	1.42
Remaining Plants	—	—	—	7,028	24	1.58	11.2	2.57
TOTAL	23,139	—	—	25,539	48	1.54	12.2	2.70

Major Utility Users of Ohio Coal in 1979

Table 4.5-4 lists the states containing utility plants that burned Ohio coal in 1979. Also listed are the Ohio coal quantities received, the percentage of coal use these quantities represented for each state, and the weighted average coal properties. The largest Ohio users of Ohio coal are listed in Table 4.5-5 along with relevant plant information and coal properties.

Table 4.5-4. States Receiving Ohio Coal Deliveries to Utility Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Ohio	27,561	52	3.70	15.7	6.78
Michigan	5,006	21	2.63	12.3	4.53
Tennessee	1,994	9	3.68	16.2	6.65
Pennsylvania	1,844	5	3.41	14.5	5.89
Alabama	548	3	2.13	11.8	3.66
Indiana	408	1	3.66	12.6	6.64
West Virginia	374	1	0.92	14.3	1.63
Wisconsin	316	3	3.08	7.0	5.22
Kentucky	171	1	2.42	15.4	4.31
Georgia	68	< 1	2.26	11.7	4.05
Florida	16	< 1	2.55	10.9	3.99
Minnesota	8	< 1	2.40	7.3	3.69
TOTAL	38,313	–	3.48	15.0	6.31

Table 4.5-5. Ohio Utility Plants Receiving Ohio Coal Deliveries in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
					Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Gavin	2,600	9.5	4,664	51	3.71	21.1	7.62
Muskingum River	1,346	6.5	3,817	100	5.20	19.4	9.90
Conesville	1,860	1.2, 5.7	3,552	100	4.35	14.2	7.87
Sammis	2,374	1.6, 4.5	2,438	65	2.84	11.1	4.74
Eastlake	648	5.6	1,983	78	3.88	11.5	6.40
Cardinal	1,186	4.8	1,913	44	2.58	13.9	4.45
Avon Lake	1,285	1.4, 4.1	1,884	82	2.99	12.9	5.06
Kyger Creek	1,055	8.2	1,363	43	3.40	14.5	6.38
Burger	546	16	1,204	83	3.77	14.0	6.28
Beckjord	1,165	2.0	1,094	43	3.10	20.6	5.88
Remaining Plants	–	–	3,649	24	3.24	13.3	5.68
TOTAL	23,139	–	27,561	52	3.70	15.7	6.78

4.6 PENNSYLVANIA

General Information

The Pennsylvania bituminous coal fields are located in the southwest portion of the state. Anthracite deposits are located in eastern Pennsylvania but are not included in this analysis. In 1977 Pennsylvania was the third largest coal-producing state behind Kentucky and West Virginia. Surface mining methods were used to produce about 46 million tons in 1977, while underground mines produced about 38 million tons. Nearly 21 million tons of Pennsylvania coal were used as metallurgical coal for the production of coke.[1]

Over one-half of the Pennsylvania coal was shipped by rail or water, 36 percent was shipped by truck, and 8 percent was used in minemouth generating plants.[1]

Pertinent facts regarding Pennsylvania coal properties are listed in Figure 4.6-1. The coal properties, taken from the coal data bases described in Section 3, are specified on a moisture-free basis for the reserves and production data bases and on an as-delivered basis for the deliveries-to-utilities data base.

Coal Employment and Production in 1977

County	Production (10^3 Tons)			Value (10^6 $)*	Number of Employees (Monthly Average)**
	Underground*	Surface*	Total*		
Washington	9,138	2,035	11,173	365	5,944
Indiana	7,627	2,823	10,450	285	5,646
Clearfield	590	7,795	8,385	153	2,534
Armstrong	3,505	3,927	7,432	147	2,382
Somerset	2,683	4,519	7,202	192	3,120
Greene	6,209	821	7,029	227	4,680
Cambria	3,558	2,526	6,083	214	5,479
Clarion	0	6,069	6,069	126	1,296
Others	5,063	15,751	20,814	458	7,226
TOTAL	38,373	46,266	84,639	2,167	38,307

* Source: Reference 1.

** Source: Reference 10.

Coal Washing in 1977

Pennsylvania coals have a relatively high pyritic sulfur content, which can be reduced by physical coal cleaning. In 1977, 66 coal cleaning plants processed nearly one-half of the coal produced in Pennsylvania.[1] The level of cleaning that these coals received is unknown.

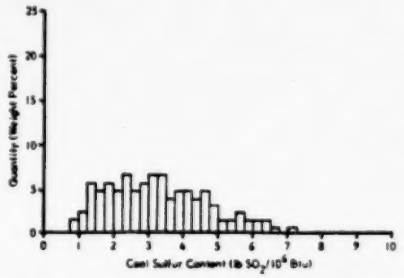
Coal Washability Data

Pertinent facts regarding the washability of Pennsylvania coals, taken from the washability data base described in Section 3, are listed here in Figure 4.6-2. The top portion of the figure provides information regarding the coal properties on a moisture-free basis before and after physical cleaning. Two levels of cleaning, PCC I and PCC II, are analyzed. The bottom portion of the figure summarizes the potential SO_2 emission reduction and energy recovery characteristics of the coals in the washability data base at the two levels of cleaning.

Figure 4.6-1. Pennsylvania Coal Properties Fact Sheet

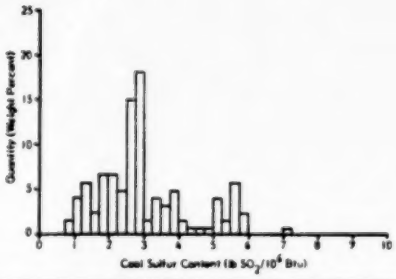
Reserves: 23,827 million tons, 623 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,496	2.32	11.05
Std. Dev.	706	1.13	3.85
Minimum	7,069	0.40	2.50
Maximum	15,520	9.40	51.90



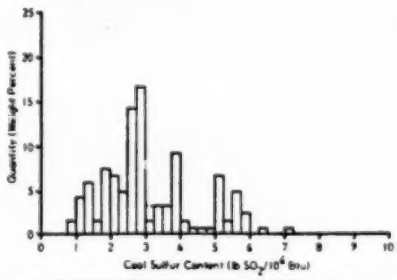
1976 Production: 84.87 million tons, 2.30 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,572	2.11	10.58
Std. Dev.	513	1.02	1.93
Minimum	11,271	0.60	5.00
Maximum	14,641	8.00	18.50



Projected 1985 Production: 99.61 million tons, 2.62 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,588	2.14	10.53
Std. Dev.	484	0.99	1.00
Minimum	11,271	0.60	5.00
Maximum	14,641	8.00	18.50



1979 Deliveries to Utilities: 46.30 million tons, 1.13 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,161	1.99	14.60
Std. Dev.	561	0.62	4.04
Minimum	9,086	0.49	5.60
Maximum	13,612	5.42	32.60

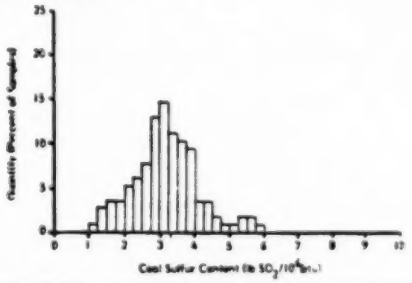
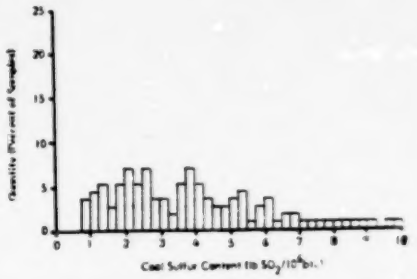


Figure 4.6-2. Pennsylvania Coal Washability Data Sheet

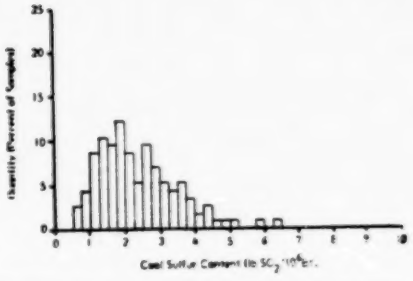
Raw Coal: 170 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,982	2.56	14.41
Std. Dev.	1,057	1.56	6.60
Minimum	7,070	0.53	4.80
Maximum	14,658	9.40	51.90



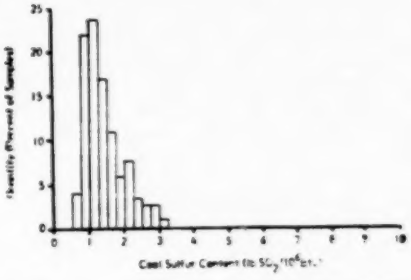
PCC I: 1-1/2 in., 1.6 sp. gr., 170 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,930	1.67	8.15
Std. Dev.	451	0.84	2.26
Minimum	12,508	0.44	3.20
Maximum	14,838	6.08	15.90



PCC II: 3/8 in., 1.3 sp. gr., 170 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,686	1.04	3.17
Std. Dev.	328	0.40	0.82
Minimum	13,482	0.46	1.50
Maximum	15,323	2.46	9.20



Emission Reduction vs. Energy Recovery:

	Emission Reduction (%)		Btu Recovery (%)	
	PCC I	PCC II	PCC I	PCC II
Mean	33.2	55.8	93.4	48.1
Std. Dev.	17.5	21.6	4.3	20.3
Minimum	-2.0	-28.0	76.7	0.4
Maximum	72.0	85.0	99.3	88.9

Pennsylvania Coal Seams

Pittsburgh Coal. This bed, the nation's largest producer in 1977,[1] extends in minable thickness over more than 5,000 square miles in Pennsylvania, West Virginia, Ohio, and Maryland. In Pennsylvania, reserves of this coal are now confined primarily to Washington and Greene counties and small areas of adjacent Allegheny, Westmoreland, and Fayette counties. Although the Pittsburgh bed is restricted to a relatively small part of Pennsylvania's bituminous coal field, its persistent thickness of four to six feet makes it one of the state's main minable sources. Most of the Pittsburgh coal comes from very large underground mines.[3]

Lower Kittanning Coal. This coal bed, mined in many Northern Appalachian states, was the nation's fourth largest producing bed in 1977.[1] It occurs as a complex of up to five splits, which may be variously combined into a single coal. The most persistent single split is the third from the bottom, with the lower two splits occurring frequently. The Lower Kittanning coal is mined by surface and underground methods in many Pennsylvania counties.[3]

Upper Freeport Coal. The Upper Freeport coal bed was the fifth largest producing bed in the U.S. in 1977 and is actively mined in many Northern Appalachian states.[1] In the eastern portion of the Pennsylvania bituminous coal field it is mined primarily by surface methods; in the western portion, large underground mines are used. The seam in the western part of the deep mining area is called the Thick Freeport or Double Freeport, because of its exceptional thickness of four to six feet; in this seam the normal Upper Freeport merges with a thick upper split, which elsewhere is separated from the main coal or, more usually, absent altogether.[3]

Middle Kittanning Coal. This bed, mined in Ohio, Pennsylvania, West Virginia, and Maryland, was the nation's sixth largest producer in 1977.[1] It is mined, primarily by surface methods, in many counties near the northern and eastern portions of the bituminous coal field. The Middle Kittanning bed is frequently split into two seams, both of which may be minable.[3]

Lower Freeport Coal. This coal is extensively mined by both surface and underground methods in the eastern portion of the Pennsylvania bituminous coal field. The lower Freeport bed occurs as a coal complex with either a single thick seam or two or more minable splits.[3]

Clarion-Brookville Coal. This coal occurs as a single, unsplit seam in a thickness of three to six feet. The upper bench (split) is usually discarded or left for roof control. The coal is relatively high in sulfur and ash content and often has one or more partings. The Clarion coal, a separate (middle) split of the Clarion-Brookville complex, is widely strip mined in many counties in the northwestern area of the bituminous coal field. The Brookville coal, the lower split of the Clarion-Brookville complex, is mined in the same areas as Clarion.[3]

Estimates of Pennsylvania Coal Available to Meet Various SO_2 Emission Regulations

Figure 4.6-3 shows the percentage of projected 1985 Pennsylvania coal production excluding metallurgical coal able to meet various emission standards before cleaning, after cleaning at each of three levels, and when used in conjunction with an FGD system. Over one-half of the Pennsylvania coal can meet a 3 lb $SO_2/10^6$ Btu emission standard. After physical cleaning, one-half of the coal can comply with a 2 lb $SO_2/10^6$ Btu limit and after chemical cleaning by a hypothetical process that removes 95 percent of the pyritic and 20 percent of the organic sulfur about one-half of the coal can meet a 1 lb $SO_2/10^6$ Btu emission limit.

Figure 4.6-4 shows the percentage of the projected 1985 Pennsylvania coal production excluding metallurgical coal able, when physically cleaned, to meet a standard stipulating both an SO_2 emission ceiling and a percentage SO_2 reduction. (The circled number next to each curve shows the value of the emission ceiling in lb $SO_2/10^6$ Btu.) The curves in this figure show that physical coal cleaning can reduce the sulfur content of most of the Pennsylvania coal by about 30 percent and about one-quarter of the coal by 40 percent. In addition, about one-half of the Pennsylvania coal, after physical cleaning, can comply with a 2 lb $SO_2/10^6$ Btu emission ceiling combined with a 20 percent SO_2 reduction standard.

Table 4.6-1 shows the potential SO_2 emissions, percentage SO_2 emissions, percentage SO_2 reduction, and cost of compliance for an SO_2 emission regulation requiring physical cleaning at 1½ inch top size and 1.6 specific gravity of those coals mined in Pennsylvania for utility use in 1979 that had sulfur contents exceeding a specified floor.

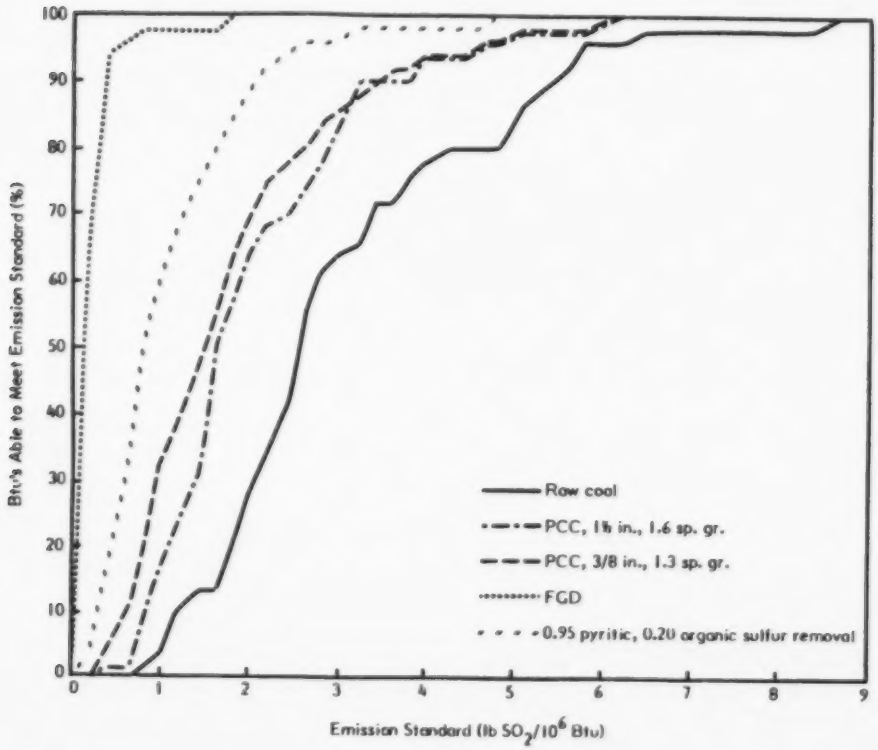


Figure 4.6-3. Percentage of Projected 1985 Pennsylvania Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization

Figure 4.6-4. Percentage of Projected 1985 Pennsylvania Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.

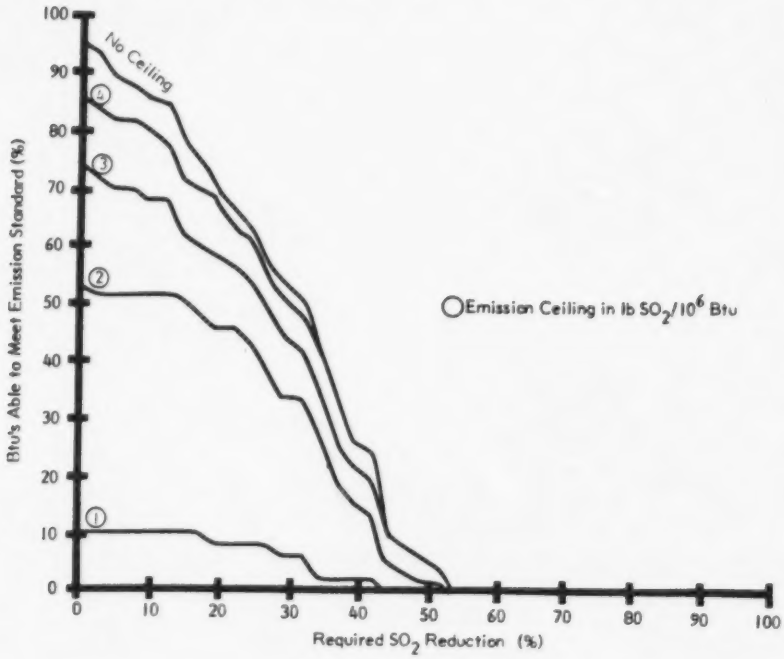


Table 4.6-1. Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Pennsylvania Coals Delivered to Utilities in 1979

Coals to Be Washed*	Quantity to Be Washed (10^3 Tons)	Total SO_2 Emissions after Selective Washing (10^3 Tons)	SO_2 Emission Reduction Achieved by Selective Washing		Levelized Cost of Washing (10^6 1979$)	Cost-Effectiveness ($/Ton SO_2)
			(10^3 Tons)	(%)		
No coals	0	1,381	0	0	0	–
Coals with SO_2 contents above floor of:						
5 lb/10^6Btu	2,798	1,292	89	6	27	300
4 lb/10^6Btu	6,450	1,236	146	11	55	380
3 lb/10^6 Btu	22,122	1,015	366	26	205	560
2 lb/10^6 Btu	30,315	936	446	32	270	610
All coals	34,365	913	469	34	313	670

* Excluding the 13,069,000 tons of coal actually washed in 1979.

Major Sources of Coal Used by Pennsylvania Utility Plants in 1979

Source states for coal delivered to Pennsylvania utilities in 1979 are listed in Table 4.6-2 along with the quantity and the weighted average sulfur and ash content of the coal from each state. Table 4.6-3 shows the Pennsylvania utility plants that imported the greatest amount of coal in 1979, ranked according to the quantity imported. Following the plant name, the combined units' size and SO_2 limits are shown. In some cases, more than one SO_2 limit applies to various units of a given plant. The remaining columns indicate the quantity imported from each state, the percentage of coal that quantity represented for each plant, and the weighted average sulfur and ash content of the imported coal.

Table 4.6-2. Source State for Coal Used in Pennsylvania Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Pennsylvania	32,102	83	1.97	15.5	3.27
West Virginia	4,387	11	2.54	12.0	4.10
Ohio	1,844	5	3.41	14.5	5.89
Maryland	262	1	2.41	14.6	4.08
Kentucky	65	< 1	0.98	6.3	1.49
TOTAL	38,661	100	2.11	15.0	3.49

Table 4.6-3. Out-of-State Coal Use by Pennsylvania Plants in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	State of Origin	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
						Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Mansfield	1,760	0.6	OH	1,829	61	3.43	14.5	5.91
Mansfield	1,760	0.6	WV	454	15	2.67	14.9	4.54
Mansfield	1,760	0.6	MD	192	6	2.67	14.9	4.54
Hatfields Ferry	1,581	3.3	WV	2,352	72	2.63	13.3	4.29
Mitchell	374	0.7	WV	656	91	2.10	6.7	3.19
Eddystone	488	0.4	WV	411	54	2.78	9.4	4.29
Phillips	381	0.7	WV	132	14	2.66	15.8	4.46
Cromby	152	0.7	WV	128	47	2.61	10.3	4.05
Elrama	488	0.6	WV	107	7	2.54	15.0	4.23
Portland	403	3.3	MD	52	7	1.88	14.6	3.14
Remaining Plants	–	–	–	247	2	1.58	9.6	2.46
TOTAL	17,412	–	–	6,559	17	2.80	12.8	4.57

Major Utility Users of Pennsylvania Coal in 1979

Table 4.6-4 lists the states containing utility plants that burned Pennsylvania coal in 1979. Also listed are the Pennsylvania coal quantities received, the percentage of coal use these quantities represented for each state, and the weighted average coal properties. The largest Pennsylvania users of Pennsylvania coal are listed in Table 4.6-5 along with relevant plant information and coal properties.

Table 4.6-4. States Receiving Pennsylvania Coal Deliveries to Utility Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Pennsylvania	32,102	83	1.97	15.5	3.27
New York	5,598	91	1.84	13.5	3.01
Maryland	3,322	65	1.56	12.5	2.54
Ohio	1,624	3	3.11	12.9	5.24
Wisconsin	1,264	10	2.97	11.3	4.82
Delaware	991	99	1.73	12.4	2.80
Michigan	809	3	2.43	10.0	3.86
New Jersey	438	20	1.21	10.6	1.88
West Virginia	73	< 1	1.21	14.5	2.08
New Hampshire	28	3	2.38	10.0	3.65
Remaining 4 States	49	< 1	2.16	12.8	3.59
TOTAL	46,299	–	1.99	14.6	3.28

Table 4.6-5. Pennsylvania Utility Plants Receiving Pennsylvania Coal Deliveries in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
					Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Homer City	1,850	1.2, 3.3	5,321	100	1.94	18.9	3.38
Mantour	1,505	3.3	3,866	100	1.61	12.8	2.57
Keystone	1,690	3.3	3,806	100	1.77	20.1	2.99
Brunner Island	1,425	3.3	3,500	100	2.17	14.1	3.48
Conemaugh	1,700	3.3	2,783	100	2.37	17.1	3.90
Shawville	610	3.3	1,757	100	2.07	13.5	3.38
Elrama	488	0.6	1,352	93	2.03	16.8	3.49
Cheswick	565	0.6	1,299	97	1.77	14.5	2.95
Armstrong	355	3.3	1,032	100	1.97	12.2	3.24
Hatfields Ferry	1,581	3.3	881	27	2.06	18.9	3.65
Remaining Plants	–	–	6,505	62	2.05	12.1	3.32
TOTAL	17,412	–	32,102	83	1.97	15.5	3.27

4.7 VIRGINIA

General Information

The Virginia coal fields are in the western portion of the state and are mined primarily in Buchanan, Wise, and Dickenson counties. In 1977, Virginia was the seventh largest coal producing state ahead of Indiana, Montana, and Alabama in the top ten producing states. Surface mining methods were used to produce about 15 million tons and underground methods were used to produce about 23 million tons. Over 6 million tons of Virginia coal were used as metallurgical coal for the production of coke.[1]

Nearly three-fourths of Virginia coal production was shipped by rail or water and one-fourth was shipped by truck in 1977.[1]

Pertinent facts regarding Virginia coal properties are listed in Figure 4.7-1. The coal properties, taken from the coal data bases described in Section 3, are specified on a moisture-free basis for the reserves and production data bases and on an as-delivered basis for the deliveries-to-utilities data base.

Coal Employment and Production in 1977

County	Production (10^3 Tons) Underground*	Surface*	Total*	Value (10^6 $)*	Number of Employees (Monthly Average)**
Buchanan	12,242	4,291	16,533	544	7,863
Wise	4,746	6,547	11,292	279	4,359
Dickenson	2,753	1,933	4,686	127	1,963
Tazewell	1,716	456	2,172	88	843
Russell	949	614	1,562	51	1,015
Lee	652	726	1,378	27	505
TOTAL	23,057	14,567	37,624	1,116	16,548

* Source: Reference 1.

** Source: Reference 11.

Coal Washing in 1977

Virginia coals are generally low in both pyritic and total sulfur and do not benefit substantially by physical coal cleaning. In 1977, 24 cleaning plants processed 32 percent of the coal.[1] The level to which these coals were cleaned is not known.

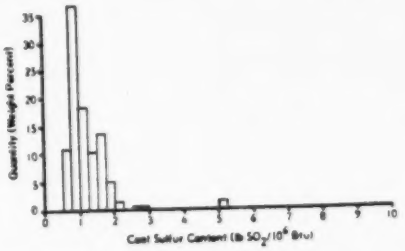
Coal Washability Data

Pertinent facts regarding the washability of Virginia coals, taken from the washability data base described in Section 3, are listed here in Figure 4.7-2. The top portion of the figure provides information regarding the coal properties on a moisture-free basis before and after physical cleaning. Two levels of cleaning, PCC I and PCC II, are analyzed. The bottom portion of the figure summarizes the potential SO_2 emission reduction and energy recovery characteristics of the coals in the washability data base at the two levels of cleaning.

Figure 4.7-1. Virginia Coal Properties Fact Sheet

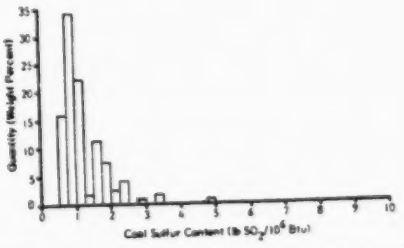
Reserves: 3,636 million tons, 99.4 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,993	0.85	9.04
Std. Dev.	895	0.43	5.31
Minimum	10,240	0.40	1.50
Maximum	15,490	3.70	31.70



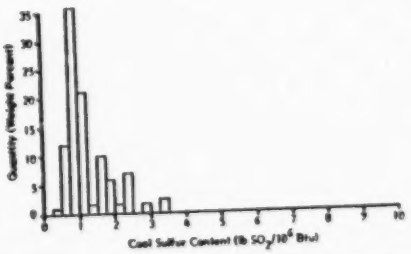
1976 Production: 40.00 million tons, 1.13 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,138	0.87	8.12
Std. Dev.	544	0.43	2.65
Minimum	10,860	0.40	3.90
Maximum	15,229	3.10	19.50



Projected 1985 Production: 46.39 million tons, 1.28 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,210	0.90	7.77
Std. Dev.	499	0.46	2.80
Minimum	10,860	0.30	3.90
Maximum	15,229	3.10	19.50



1979 Deliveries to Utilities: 13.39 million tons, 0.33 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,305	1.02	12.88
Std. Dev.	536	0.35	3.15
Minimum	10,424	0.24	4.80
Maximum	14,236	2.80	23.10

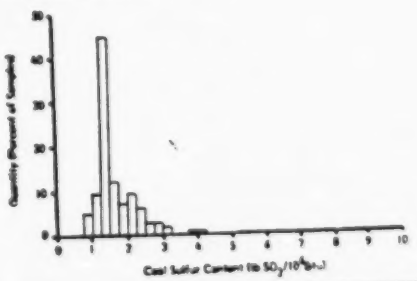
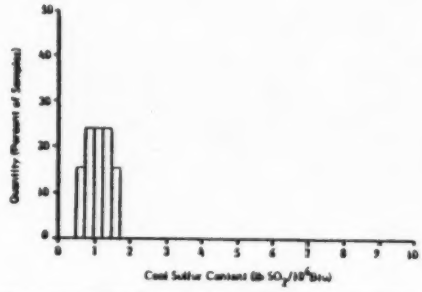


Figure 4.7-2. Virginia Coal Washability Data Sheet

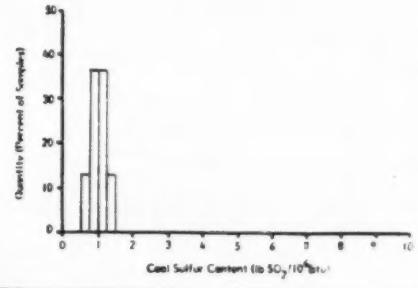
Raw Coal: 8 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,715	0.77	10.04
Std. Dev.	1,143	0.23	7.83
Minimum	11,872	0.48	1.97
Maximum	14,828	1.17	22.77



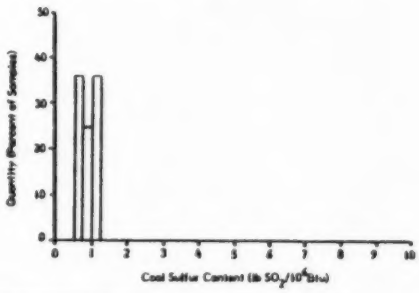
PCC I: 1-1/2 in., 1.6 sp. gr., 8 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,486	0.74	5.03
Std. Dev.	408	0.19	2.71
Minimum	13,576	0.48	1.50
Maximum	14,899	1.07	10.30



PCC II: 3/8 in., 1.3 sp. gr., 8 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,876	0.69	2.46
Std. Dev.	180	0.15	0.99
Minimum	14,513	0.49	1.10
Maximum	15,035	0.88	4.10



Emission Reduction vs. Energy Recovery:

	Emission Reduction (%)		Btu Recovery (%)	
	PCC I	PCC II	PCC I	PCC II
Mean	7.6	15.3	97.0	70.0
Std. Dev.	4.7	11.5	2.8	16.6
Minimum	1.0	0	92.0	38.9
Maximum	14.0	30.0	99.8	95.8

Virginia Coal Seams

Kennedy Coal. This bed, found in the Norton Formation, was Virginia's largest producer in 1978; it accounted for 8 percent of the state's production that year. The Kennedy seam is between two and ten feet thick and is mined by both surface and underground methods, primarily in Buchanan County.[7,8]

Blair Coal. The Blair coal, found in the Wise Formation, accounted for about 7 percent of Virginia's coal production in 1978. The coal is between two and four feet thick, has a hard and clear structure, and is usually low in sulfur and ash content. It is mined primarily by surface methods in Wise County and by underground methods in Buchanan County.[3,7,8]

Dorchester Coal. This bed is the lowest in the Wise Formation and is mined principally in Wise County by both surface and underground methods. The seam is from two to six feet thick and in some places contains a streak of clay, one to six inches thick, and dirty coal about two feet below the seam top.[3,7,8]

Splash Dam Coal. The Splash Dam Coal is found in a 15-square-mile area of Dickenson and Buchanan counties in thicknesses of between three and five feet. The coal is intermediate in luster and has a bluish gray cast. The cleavage plains are not pronounced, and the coal breaks into irregular shapes. The seam is characterized by one or two thin shale partings to which the coal tends to adhere strongly. The principal markets for this coal have been provided by metallurgical and high-grade industrial steam coal users.[3]

Jawbone Coal. This coal bed, one of the higher beds in the Lee Formation, is mined by both underground and surface methods. In some places it lies as much as 100 feet above the Tiller bed, while in others the two coals join to form one bed. Alone, the Jawbone coal seam is about six feet thick; when combined with the Tiller, however, it forms a coal zone thicker than 15 feet. Numerous bone partings make this coal high in ash, which can be readily removed by washing.[3,7,8]

Clintwood Coal. This seam is in the Wise Formation and is located 70 to 150 feet above the Blair coal in Buchanan, Dickenson, Lee, and Wise counties. The minable seam is composed of five benches; the middle three are generally mined. These three benches have an average total thickness of ten feet and are separated by two small shale partings. The coal generally has a slender columnar structure and is not dusty. The Clintwood coal is high in heating value, low in both ash and sulfur, and easy to clean by mechanical methods. Although it is used primarily as a metallurgical coal for the production of coke, it is suitable for use as a steam coal.[3,7]

Pocahontas No. 3 Coal. This bed is one of the deepest in the Pocahontas Formation and is mined primarily in Buchanan County from shaft mines that are about 1,300 feet deep. Pocahontas No. 3 is medium- to low-volatile bituminous coal ranging in thickness from two to eleven feet with a usual thickness of between four and five feet. Although it is used primarily as a metallurgical coal for the production of coke, its low fusion temperature also makes it suitable for domestic use in clinker-type stokers.[3,7]

Imboden Coal. This bed, 225 to 500 feet above the Clintwood coal, crops out in Buchanan, Dickenson, Lee, and Wise counties. The seam is two to ten feet thick and in some sections carries one to eight partings, up to three feet thick, composed of shale, mud, dirty coal, coal and laminated shale, and sulfur streaks. The Imboden coal is a high-quality coking coal and is also suitable for use as a steam coal.[3,7]

Estimates of Virginia Coal Available to Meet Various SO_2 Emission Regulations

Figure 4.7-3 shows the percentage of projected 1985 Virginia coal production excluding metallurgical coal able to meet various emission standards before cleaning, after cleaning at each of three levels, and when used in conjunction with an FGD system. Virginia coal is low in sulfur and can comply with relatively low SO_2 emission limits without physical cleaning. In addition, cleaning does not substantially increase the quantity of compliance coal.

Figure 4.7-4 shows the percentage of the projected 1985 Virginia coal production excluding metallurgical coal able, when physically cleaned, to meet a standard stipulating both an SO_2 emission ceiling and a percentage SO_2 reduction. (The circled number next to each curve shows the value of the emission ceiling in lb $SO_2/10^6$ Btu.) The curves in this figure show again that Virginia coals can comply with relatively low emission limits but that they are not able to comply with regulations requiring a large percentage SO_2 reduction.

Table 4.7-1 shows the potential SO_2 emissions, percentage SO_2 reduction, and cost of compliance for an SO_2 emission regulation requiring physical cleaning at 1½ inch top size and 1.6 specific gravity of those coals mined in Virginia for utility use in 1979 that had sulfur contents exceeding a specified floor.

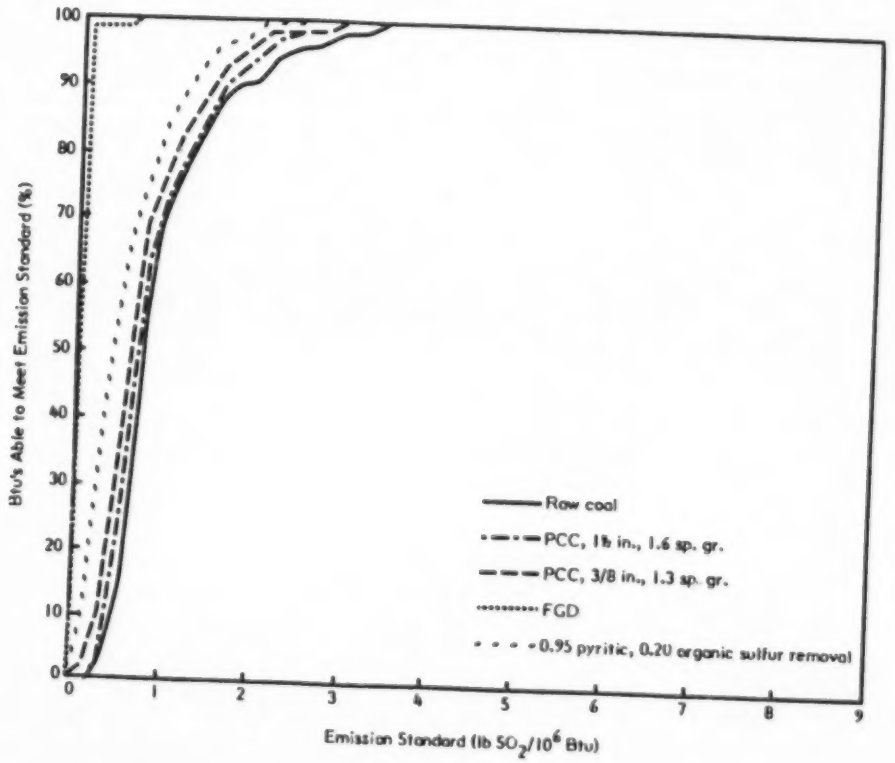


Figure 4.7-3. Percentage of Projected 1985 Virginia Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization

Figure 4.7-4. Percentage of Projected 1985 Virginia Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1⅛", 1.6 sp. gr.

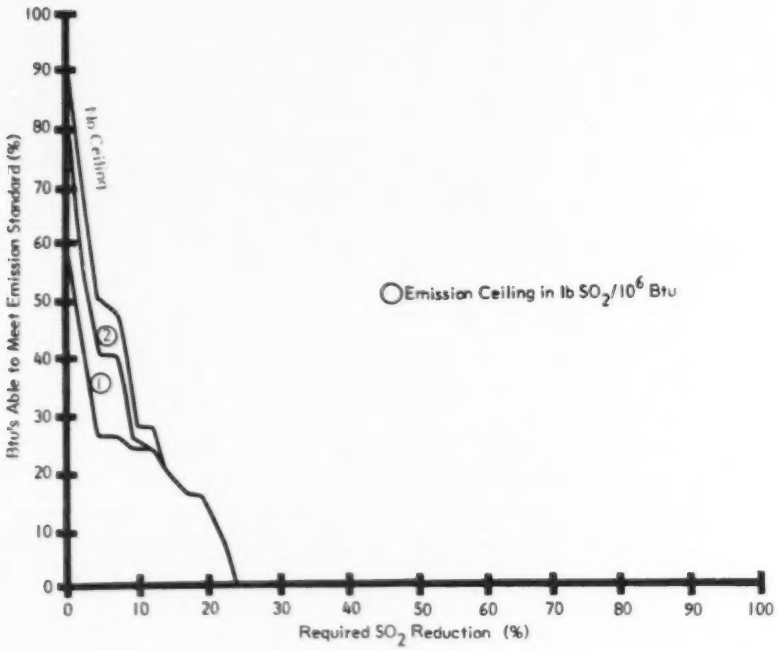


Table 4.7-1. Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Virginia Coals Delivered to Utilities in 1979

Coals to Be Washed*	Quantity to Be Washed (10^3 Tons)	Total SO_2 Emissions after Selective Washing (10^3 Tons)	SO_2 Emission Reduction Achieved by Selective Washing		Levelized Cost of Washing (10^6 1979$)	Cost-Effectiveness ($/Ton SO_2)
			(10^3 Tons)	(%)		
No coals	0	251	0	0	0	–
Coals with SO_2 contents above floor of:						
4 lb/10^6Btu	115	251	< 1	< 1	< 1	–
3 lb/10^6Btu	457	248	3	1	5	1,670
2 lb/10^6 Btu	2,426	239	12	5	26	2,170
1 lb/10^6 Btu	11,941	224	28	11	98	3,500
All coals	12,537	223	28	11	104	3,710

* Excluding the 849,000 tons of coal actually washed in 1979.

Major Sources of Coal Used by Virginia Utility Plants in 1979

Source states for coal delivered to Virginia utilities in 1979 are listed in Table 4.7-2 along with the quantity and the weighted average sulfur and ash content of the coal from each state. Table 4.7-3 shows the Virginia utility plants that imported the greatest amount of coal in 1979, ranked according to the quantity imported. Following the plant name, the combined units' size and SO_2 limits are shown. In some cases, more than one SO_2 limit applies to various units of a given plant. The remaining columns indicate the quantity imported from each state, the percentage of coal that quantity represented for each plant, and the weighted average sulfur and ash content of the imported coal.

Table 4.7-2. Source State for Coal Used in Virginia Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Virginia	2,602	51	0.81	15.4	1.34
Kentucky	1,744	34	0.93	9.6	1.49
West Virginia	758	15	0.83	10.5	1.33
TOTAL	5,104	100	0.86	12.7	1.39

Table 4.7-3. Out-of-State Coal Use by Virginia Plants in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	State of Origin	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
						Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Chesterfield	802	2.6	KY	986	99	1.03	8.8	1.62
Chesterfield	802	2.6	WV	3	< 1	1.18	11.3	1.87
Potomac River	459	1.1	WV	376	39	0.72	8.7	1.11
Potomac River	459	1.1	KY	339	35	0.71	8.0	1.11
Bremo Bluff	240	2.6	WV	319	57	0.97	11.2	1.57
Bremo Bluff	240	2.6	KY	244	43	1.05	10.9	1.71
Clinch River	714	2.6	KY	156	9	0.64	15.0	1.06
Glen Lyn	331	2.6	WV	60	8	0.80	16.9	1.37
Glen Lyn	331	2.6	KY	15	2	1.04	16.7	1.89
TOTAL	2,578	–	–	2,503	49	0.90	9.8	1.44

Major Utility Users of Virginia Coal in 1979

Table 4.7-4 lists the states containing utility plants that burned Virginia coal in 1979. Also listed are the Virginia coal quantities received, the percentage of coal use these quantities represented for each state, and the weighted average coal properties. The largest Virginia users of Virginia coal are listed in Table 4.7-5 along with relevant plant information and coal properties.

Table 4.7-4. States Receiving Virginia Coal Deliveries to Utility Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
North Carolina	6,596	31	0.99	13.0	1.62
Virginia	2,602	51	0.81	15.4	1.34
South Carolina	954	16	1.27	12.7	2.05
Missouri	601	3	1.38	8.2	2.12
West Virginia	574	2	1.07	15.7	1.87
Kentucky	532	2	0.61	6.4	0.90
Tennessee	502	2	1.59	13.8	2.68
New Jersey	431	20	1.26	7.4	1.85
Georgia	297	2	1.18	11.5	1.93
Illinois	170	< 1	1.39	11.9	2.27
Michigan	113	< 1	0.87	9.8	1.36
Alabama	10	< 1	0.90	15.9	1.60
Maryland	4	< 1	2.00	14.0	3.18
TOTAL	13,385	–	1.02	12.9	1.66

Table 4.7-5. Virginia Utility Plants Receiving Virginia Coal Deliveries in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
					Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Clinch River	714	2.6	1,591	91	0.76	15.9	1.25
Glen Lyn	331	2.6	721	91	0.93	17.0	1.59
Potomac River	459	1.1	250	26	0.80	8.8	1.23
Brantly	32	2.6	18	100	0.99	8.0	1.50
Portsmouth	400	2.6	18	82	0.77	7.9	1.16
Chesterfield	802	2.6	4	< 1	1.02	9.2	1.59
TOTAL	2,578	–	2,602	51	0.81	15.4	1.34

4.8 WEST VIRGINIA

General Information

Coal occurs in all but 2 of the 55 counties of West Virginia and is mined in 33 counties in the southern and north central portions of the state.[3,12] In 1977 West Virginia was the second largest coal-producing state behind Kentucky. About 74 million tons were produced from underground mines and nearly 22 million tons were produced from surface mines. In 1977, over 23 million tons of West Virginia coal were used as metallurgical coal for the production of coke.[1]

About 83 percent was shipped by rail or water in 1977, while 10 percent was shipped by truck; only 6 percent was used in minemouth generating plants.[1]

Pertinent facts regarding northern West Virginia and southern West Virginia coal properties are listed in Figures 4.8-1 and 4.8-2, respectively. The coal properties, taken from the coal data bases described in Section 3, are specified on a moisture-free basis for the reserves and production data bases and on an as-delivered basis for the deliveries-to-utilities data base.

Coal Employment and Production in 1977

County	Production (10^3 Tons) Underground*	Surface*	Total*	Value (10^6 $)*	Number of Employees (Monthly Average)**
Monongalia	9,329	1,110	10,439	210	3,669
McDowell	7,580	865	8,445	402	7,263
Boone	6,197	1,883	8,080	253	5,565
Logan	5,362	1,594	6,956	224	5,115
Wyoming	6,378	288	6,666	284	6,557
Kanawha	4,426	2,222	6,647	192	4,038
Raleigh	5,276	993	6,269	294	5,476
Marion	4,917	102	5,019	147	3,786
Others	24,044	12,867	36,911	955	29,629
TOTAL	73,509	21,924	95,433	2,961	71,098

* Source: Reference 1.

** Source: Reference 12.

Coal Washing in 1977

Coal from northern West Virginia is generally medium to high in both pyritic sulfur and total sulfur and is amenable to sulfur reduction by physical coal cleaning. Southern West Virginia coal, however, is low in both pyritic and total sulfur and does not benefit as much from coal cleaning. In 1977, 135 coal cleaning plants processed 55 percent of West Virginia's coal.[1] The level to which these coals were cleaned is unknown.

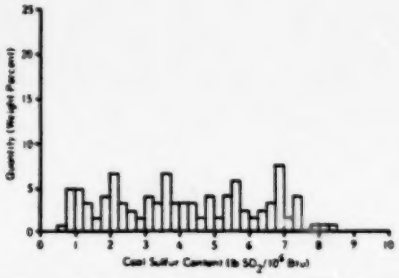
Coal Washability Data

Pertinent facts regarding the washability of northern and southern West Virginia coals, taken from the washability data base described in Section 3, are listed here in Figures 4.8-3 and 4.8-4, respectively. The top portion of the figures provides information regarding the coal properties on a moisture-free basis before and after physical cleaning. Two levels of cleaning, PCC I and PCC II, are analyzed. The bottom portion of the figures summarizes the potential SO_2 emission reduction and energy recovery characteristics of the coals in the washability data base at the two levels of cleaning.

Figure 4.8-1. Northern West Virginia Coal Properties Fact Sheet

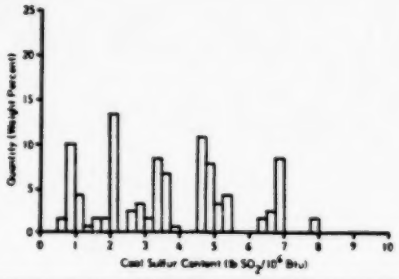
Reserves: 22,210 million tons, 574 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,229	2.73	12.17
Std. Dev.	999	1.37	6.12
Minimum	9,186	0.40	1.50
Maximum	15,360	6.60	37.50



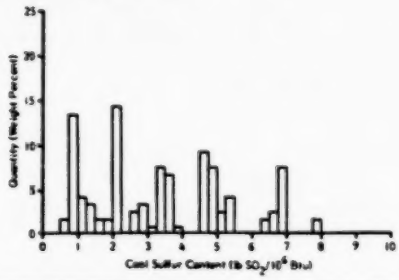
1976 Production: 46.90 million tons, 1.28 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,607	2.44	9.31
Std. Dev.	786	1.30	2.44
Minimum	9,186	0.40	3.30
Maximum	15,030	5.50	21.70



Projected 1985 Production: 52.80 million tons, 1.38 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,524	2.29	9.65
Std. Dev.	845	1.33	2.63
Minimum	9,186	0.40	3.30
Maximum	15,030	5.50	21.70



1979 Deliveries to Utilities: 31.26 million tons, 0.77 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,270	2.70	12.68
Std. Dev.	663	1.02	3.42
Minimum	10,023	0.30	2.80
Maximum	14,142	6.70	23.70

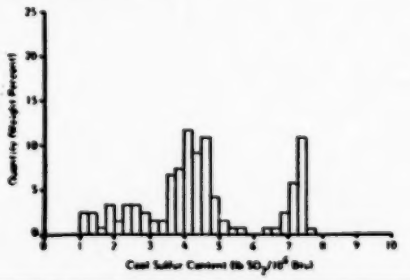
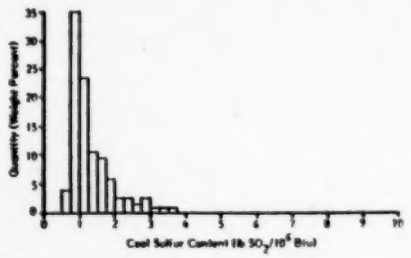


Figure 4.8-2. Southern West Virginia Coal Properties Fact Sheet

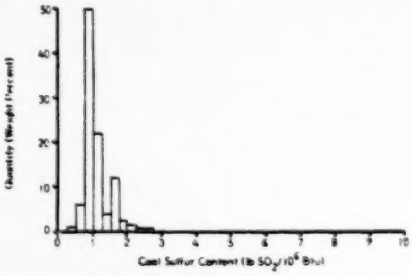
Reserves: 17,267 million tons, 471 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,034	0.94	7.89
Std. Dev.	715	0.45	3.75
Minimum	11,000	0.10	1.30
Maximum	15,570	4.30	26.10



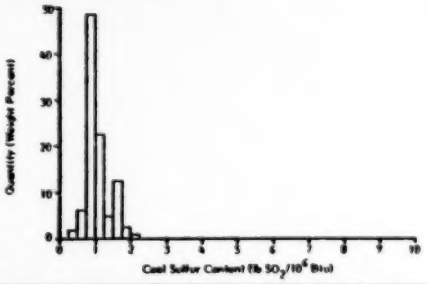
1976 Production: 61.22 million tons, 1.74 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,202	0.81	7.34
Std. Dev.	535	0.49	2.17
Minimum	12,469	0.30	3.40
Maximum	15,390	6.60	15.60



Projected 1985 Production: 87.95 million tons, 2.42 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,174	0.81	7.40
Std. Dev.	550	0.45	2.27
Minimum	12,469	0.30	3.40
Maximum	15,390	6.80	15.60



1979 Deliveries to Utilities: 17.46 million tons, 0.42 quadrillion Btu

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	11,926	0.84	13.46
Std. Dev.	602	0.25	3.12
Minimum	9,912	0.30	4.60
Maximum	14,129	3.80	27.60

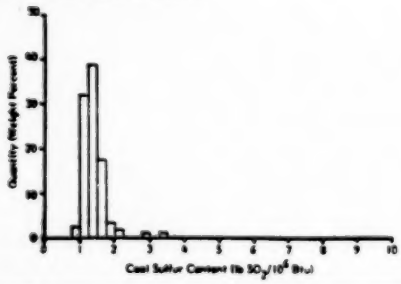
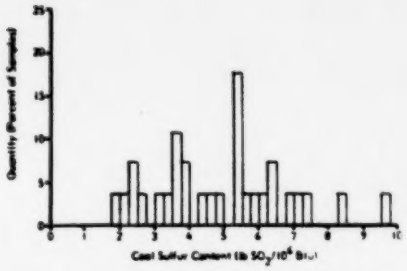


Figure 4.8-3. Northern West Virginia Coal Washability Data Sheet

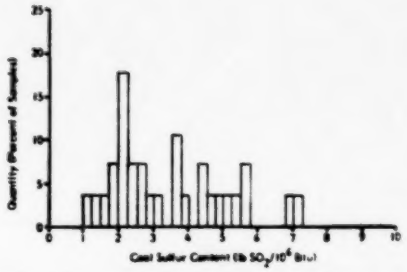
Raw Coal: 30 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	12,647	3.06	15.74
Std. Dev.	1,266	1.21	8.21
Minimum	9,186	1.06	6.63
Maximum	13,973	6.33	37.53



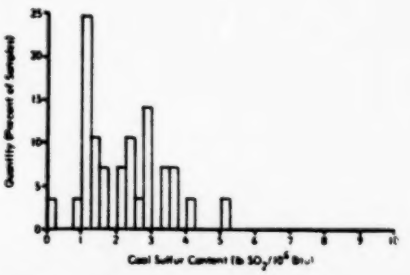
PCC I: 1-1/2 in., 1.6 sp. gr., 30 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,721	2.35	8.60
Std. Dev.	369	1.09	2.05
Minimum	12,744	0.88	6.10
Maximum	14,282	4.82	13.90



PCC II: 3/8 in., 1.3 sp. gr., 30 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,449	1.54	3.75
Std. Dev.	225	0.79	0.53
Minimum	13,835	0.15	2.80
Maximum	14,968	3.56	5.30



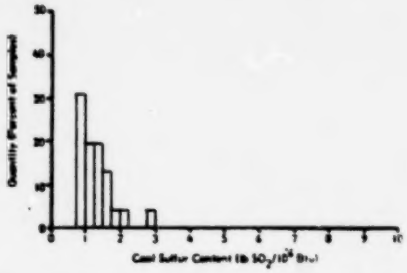
Emission Reduction vs. Energy Recovery:

	Emission Reduction (%)		Btu Recovery (%)	
	PCC I	PCC II	PCC I	PCC II
Mean	28.6	55.5	93.2	45.8
Std. Dev.	16.5	17.7	5.2	16.9
Minimum	4.0	26.0	78.1	12.0
Maximum	63.0	91.0	98.9	72.7

Figure 4.8-4. Southern West Virginia Coal Washability Data Sheet

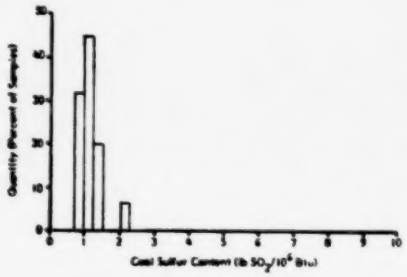
Raw Coal: 16 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,064	0.90	12.73
Std. Dev.	901	0.35	5.84
Minimum	11,000	0.59	5.30
Maximum	14,210	1.90	26.07



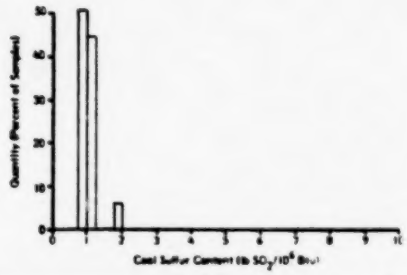
PCC I: 1-1/2 in., 1.6 sp. gr., 16 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	13,976	0.83	6.69
Std. Dev.	460	0.21	2.41
Minimum	13,202	0.59	3.90
Maximum	14,604	1.42	10.70



PCC II: 3/8 in., 1.3 sp. gr., 16 Samples

	Heating Value (Btu/lb)	Sulfur Content (%)	Ash Content (%)
Mean	14,625	0.79	2.40
Std. Dev.	249	0.17	0.57
Minimum	14,220	0.63	1.50
Maximum	15,035	1.35	3.10



Emission Reduction vs. Energy Recovery:

	Emission Reduction (%)		Btu Recovery (%)	
	PCC I	PCC II	PCC I	PCC II
Mean	10.1	16.5	96.5	55.5
Std. Dev.	11.9	15.7	2.4	19.3
Minimum	0.0	-5.0	90.6	22.6
Maximum	42.0	47.0	99.3	80.5

Northern West Virginia Coal Seams

Pittsburgh Coal. This is the largest coal-producing bed in the United States[1] and the major single source of coal mined in West Virginia, accounting for about 25 percent of the coal produced in the state. It is mined by both surface and underground methods over an area of 2,100 square miles in northern West Virginia and is used as a utility steam coal and as a coking coal. The coal is usually double-bedded (i.e., composed of two benches) but occasionally multiple-bedded (i.e., composed of more than two). It ranges from two to twenty feet in thickness, with the greatest thickness in the Potomac River Valley and an average thickness of about seven feet.[3]

Lower Kittanning Coal. This coal persists in minable thickness over a 2,640-square-mile area in northern West Virginia. It is mined by both surface and underground methods for use as a steam coal by utilities. The Lower Kittanning coal is multiple-bedded and two to twelve feet thick, with an average thickness of about five feet.[3]

Upper Freeport Coal. This coal is mined in a 1,165-square-mile area by underground and surface methods for use in the steam and coking coal markets. It is double- or multiple-bedded and ranges from two to twelve feet in thickness, with an average thickness of about five feet.[3]

Redstone Coal. This utility and by-product coal persists in minable thickness over a 300-square-mile area in northern West Virginia. It ranges from two to six feet in thickness and is usually free of partings but frequently contains clay dikes.[3]

Southern West Virginia Coal Seams

Pocahontas No. 3 Coal. This is a high-quality, low-volatile metallurgical coal that is low in both sulfur and ash. It is by far the most important seam in the Pocahontas Formation and one of the most important seams in West Virginia. It persists in a minable thickness of between two and ten feet over a 650-square-mile area in the state.[3]

Lower Cedar Grove Coal. This coal seam, providing steam coal for utilities, lies just below the Cedar Grove metallurgical coal seam in the southernmost counties of the state. The Lower Cedar Grove seam covers an area of about 365 square miles, is multiple-bedded, low in sulfur and ash, and between two and six feet in thickness.[3]

Sewell Coal. The Sewell coal, covering an area of about 2,000 square miles in southern and southeastern West Virginia, is mined extensively for use in both the steam and coking coal markets. The coal is usually multiple-bedded, soft, and columnar. Its thickness ranges from two to ten feet and averages about three feet.[3]

Pocahontas No. 4 Coal. This coal is located about 85 feet above the Pocahontas No. 3 coal over an area of about 155 square miles at the southern tip of West Virginia. The coal is suitable for use as both a steam coal and a metallurgical coal. Pocahontas No. 4 coal is multiple-bedded, soft, columnar, and very irregular. It ranges from three to six feet in thickness.[3]

Eagle Coal. The Eagle coal, known also as Middle War Eagle and Mahawk coal, is suitable for both the steam and metallurgical coal markets. It occurs over a 1,360-square-mile area in the central portion of West Virginia. It is double- or multiple-bedded and between two and four feet thick.[3]

Campbell Creek Coal. This coal, also known as No. 2 Gas and Upper War Eagle coal, is used as both a steam and a metallurgical coal. It is minable over a 2,100-square-mile area of central West Virginia. It generally occurs as a multiple-bedded, splint type coal between two and ten feet thick.[3]

Estimates of Northern West Virginia Coal Available to Meet Various SO_2 Emission Regulations

Figure 4.8-5 shows the percentage of projected 1985 northern West Virginia coal production excluding metallurgical coal able to meet various emission standards before cleaning, after cleaning at each of three levels, and when used in conjunction with an FGD system. Coal from northern West Virginia is quite high in sulfur and unable to comply with low SO_2 emission limits. Physical cleaning can bring an additional 10 to 20 percent of the northern West Virginia coal into compliance with a given SO_2 emission limit. If 95 percent of the pyritic and 20 percent of the organic sulfur were removed by a hypothetical chemical coal cleaning process, one-half of the coal could comply with a 1.5 lb $SO_2/10^6$ Btu emission limit.

Figure 4.8-6 shows the percentage of the projected 1985 northern West Virginia coal production excluding metallurgical coal able, when physically cleaned, to meet a standard stipulating both an SO_2 emission ceiling and a percentage SO_2 reduction. (The circled number next to each curve shows the value of the emission ceiling in lb $SO_2/10^6$ Btu.) The curves in this figure show that the sulfur content of most of the northern West Virginia coal can be reduced by 20 percent by physical cleaning and that physical cleaning can bring about one-half of the coal into compliance with a 4 lb $SO_2/10^6$ Btu ceiling combined with a 20 percent SO_2 reduction standard.

Table 4.7-1 shows the potential SO_2 emissions, percentage SO_2 reduction, and cost of compliance for an SO_2 emission regulation requiring physical cleaning at 1½ inch top size and 1.6 specific gravity of those coals mined in northern West Virginia for utility use in 1979 that had sulfur contents exceeding a specified floor.

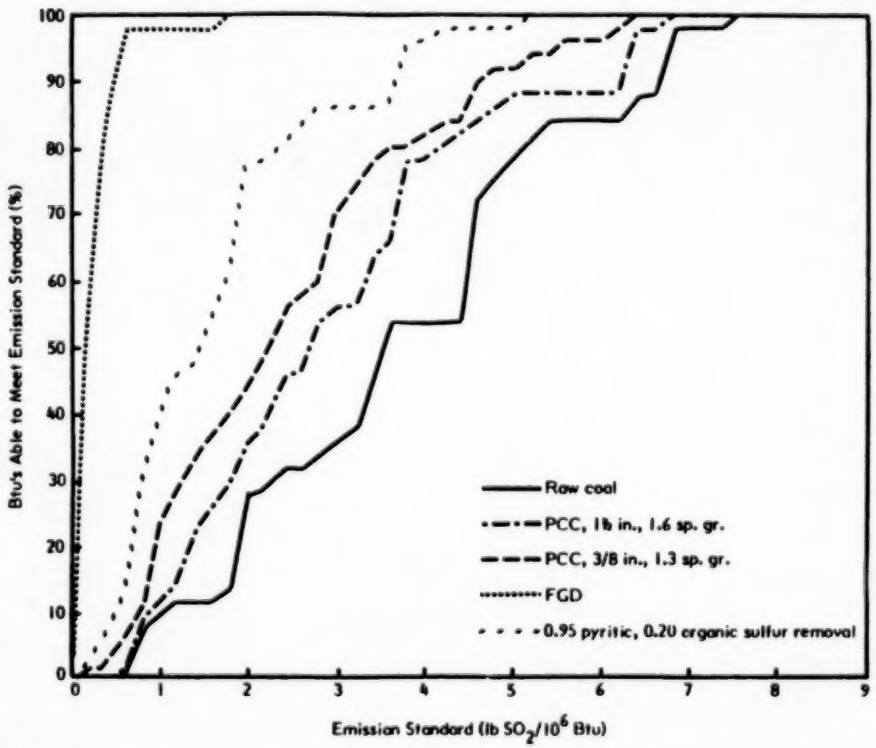

Btu's Able to Meet Emission Standard (%)
Emission Standard (lb $SO_2/10^6$ Btu)
Raw coal
PCC, 1½ in., 1.6 sp. gr.
PCC, 3/8 in., 1.3 sp. gr.
FGD
0.95 pyritic, 0.20 organic sulfur removal

Figure 4.8-5. **Percentage of Projected 1985 Northern West Virginia Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization**

Figure 4.8-6. Percentage of Projected 1985 Northern West Virginia Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1¼", 1.6 sp. gr.

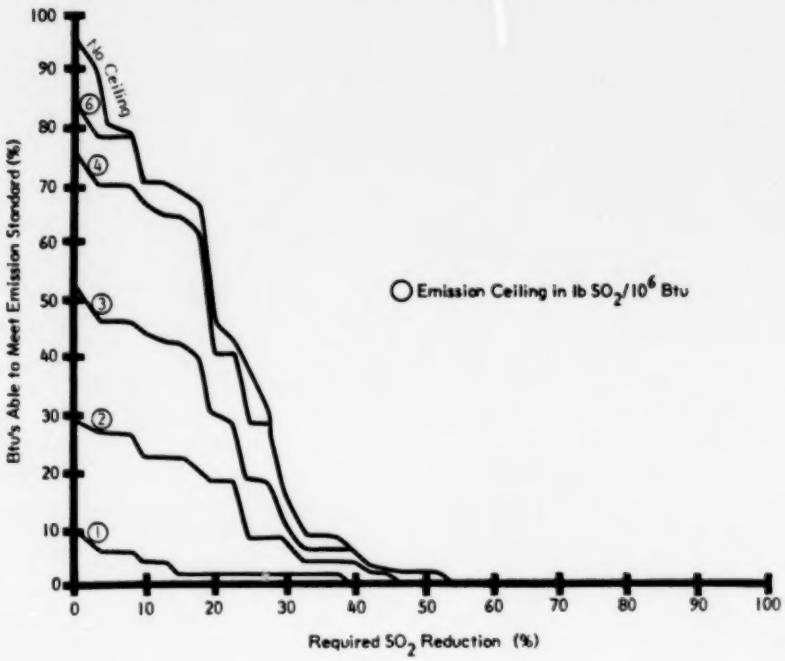


Table 4.8-1. Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Northern West Virginia Coals Delivered to Utilities in 1979

Coals to Be Washed*	Quantity to Be Washed (10^3 Tons)	Total SO_2 Emissions after Selective Washing (10^3 Tons)	SO_2 Emission Reduction Achieved by Selective Washing		Levelized Cost of Washing (10^6 1979$)	Cost-Effectiveness ($/Ton SO_2)
			(10^3 Tons)	(%)		
No coals	0	1,390	0	0	0	–
Coals with SO_2 contents above floor of:						
5 lb/10^6Btu	7,838	1,290	100	7	66	660
4 lb/10^6Btu	16,809	1,173	217	16	130	600
3 lb/10^6 Btu	20,307	1,138	252	18	153	610
2 lb/10^6 Btu	22,233	1,125	265	19	170	640
All coals	24,731	1,114	276	20	199	720

* Excluding the 6,528,000 tons of coal actually washed in 1979.

Estimates of Southern West Virginia Coal Available to Meet Various SO_2 Emission Regulations

Figure 4.8-7 shows the percentage of projected 1985 southern West Virginia coal production excluding metallurgical coal able to meet various emission standards before cleaning, after cleaning at each of three levels, and when used in conjunction with an FGD system. Coals from southern West Virginia are much lower in sulfur than those from the northern portion of the state and are able to comply with much lower SO_2 emission limits. Physical cleaning is relatively ineffective in lowering the sulfur content of southern West Virginia coal.

Figure 4.8-8 shows the percentage of the projected 1985 southern West Virginia coal production excluding metallurgical coal able, when physically cleaned, to meet a standard stipulating both an SO_2 emission ceiling and a percentage SO_2 reduction. (The circled number next to each curve shows the value of the emission ceiling in lb $SO_2/10^6$ Btu.) The curves in this figure show again that southern West Virginia coals can comply with relatively low emission limits but that they are not able to comply with regulations requiring a large percentage SO_2 reduction.

Table 4.8-2 shows the potential SO_2 emissions, percentage SO_2 reduction, and cost of compliance for an SO_2 emission regulation requiring physical cleaning at 1½ inch top size and 1.6 specific gravity of those coals mined in southern West Virginia for utility use in 1979 that had sulfur contents exceeding a specified floor.

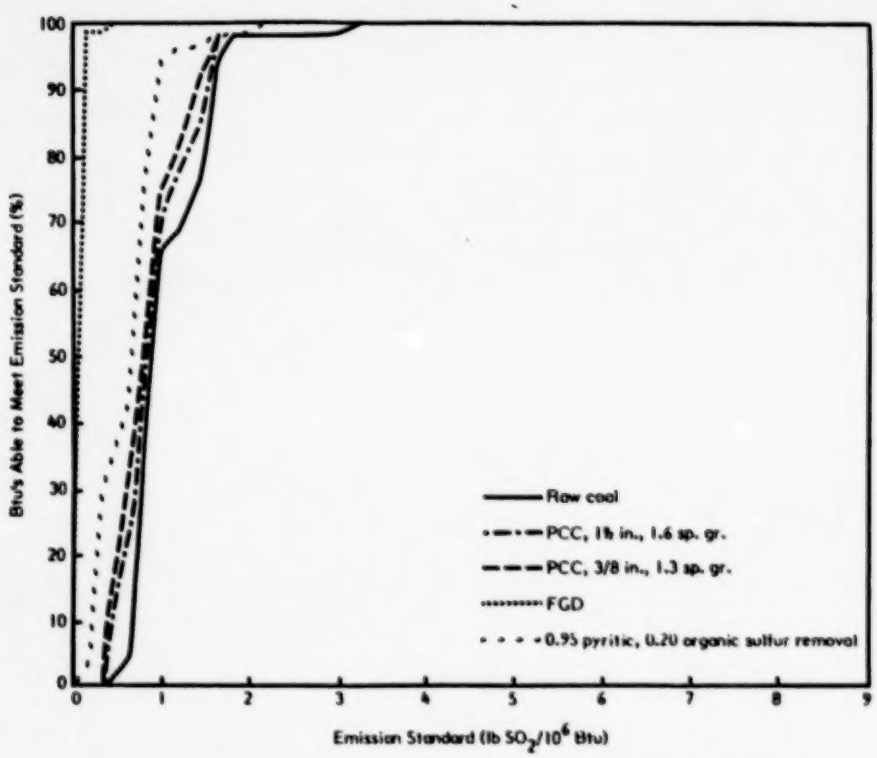


Figure 4.8-7. **Percentage of Projected 1985 Southern West Virginia Coal Production Able to Meet Various Emission Limits Using Physical Coal Cleaning and Flue Gas Desulfurization**

Figure 4.8-8. Percentage of Projected 1985 Southern West Virginia Coal Production Able to Meet Various SO_2 Emission Standards Defined by an Emission Ceiling and Percentage SO_2 Reduction Using Physical Coal Cleaning at 1½", 1.6 sp. gr.

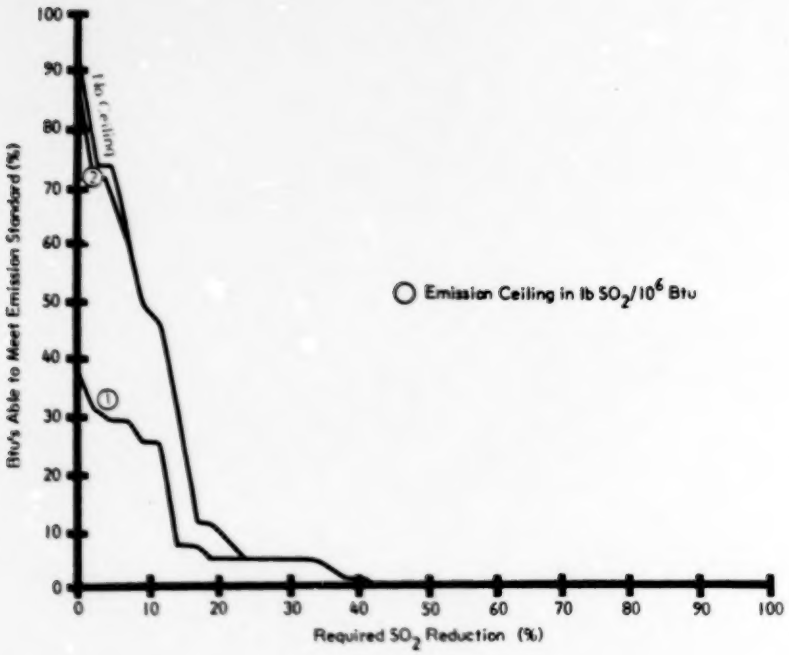


Table 4.8-2. Potential SO_2 Emission Reductions and Costs Due to Selective Washing of Southern West Virginia Coals Delivered to Utilities in 1979

Coals to Be Washed*	Quantity to Be Washed (10^3 Tons)	Total SO_2 Emissions after Selective Washing (10^3 Tons)	SO_2 Emission Reduction Achieved by Selective Washing		Levelized Cost of Washing (10^6 1979$)	Cost-Effectiveness ($/Ton SO_2)
			(10^3 Tons)	(%)		
No coals	0	267	0	0	0	–
Coals with SO_2 contents above floor of:						
4 lb/10^6 Btu	82	267	< 1	< 1	< 1	–
3 lb/10^6 Btu	337	263	4	2	4	1,000
2 lb/10^6 Btu	933	260	8	3	8	1,000
1 lb/10^6 Btu	15,677	236	31	12	123	3,970
All coals	16,013	236	31	12	126	4,060

* Excluding the 1,450,000 tons of coal actually washed in 1979.

Major Sources of Coal Used by West Virginia Utility Plants in 1979

Source states for coal delivered to West Virginia utilities in 1979 are listed in Table 4.8-3 along with the quantity and the weighted average sulfur and ash content of the coal from each state. Table 4.8-4 shows the West Virginia utility plants that imported the greatest amount of coal in 1979, ranked according to the quantity imported. Following the plant name, the combined units' size and SO_2 limits are shown. In some cases, more than one SO_2 limit applies to various units of a given plant. The remaining columns indicate the quantity imported from each state, the percentage of coal that quantity represented for each plant, and the weighted average sulfur and ash content of the imported coal.

Table 4.8-3. Source State for Coal Used in West Virginia Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
West Virginia	23,648	86	2.06	13.8	3.41
Kentucky	2,703	10	0.96	12.2	1.63
Virginia	574	2	1.07	15.7	1.87
Ohio	374	1	0.92	14.3	1.63
Maryland	235	1	1.46	18.1	2.57
Pennsylvania	73	<1	1.21	14.5	2.08
TOTAL	27,607	100	1.91	13.7	3.17

Table 4.8-4. Out-of-State Coal Use by West Virginia Plants in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	State of Origin	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
						Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Sporn	1,037	3.2	KY	683	31	0.98	15.0	1.70
Sporn	1,037	3.2	VA	560	25	1.07	15.7	1.87
Sporn	1,037	3.2	OH	292	13	0.89	14.3	1.59
Fort Martin	1,107	3.1	KY	1,064	36	0.89	8.4	1.43
Mitchell	1,460	7.5	KY	337	10	1.14	13.9	2.02
Mitchell	1,460	7.5	OH	77	2	1.03	14.5	1.81
Harrison	1,920	5.1	KY	326	10	0.86	15.1	1.50
Mount Storm	1,686	2.7	MD	235	8	1.46	18.1	2.57
Pleasants	626	1.2	KY	123	10	1.12	14.1	1.92
Amos	2,900	1.6	KY	96	1	0.97	14.5	1.73
Remaining Plants	–	–	–	166	1	1.17	14.3	2.02
TOTAL	12,448	–	–	3,959	14	1.01	13.3	1.74

Major Utility Users of West Virginia Coal in 1979

Table 4.8-5 lists the states containing utility plants that burned West Virginia coal in 1979. Also listed are the West Virginia coal quantities received, the percentage of coal use these quantities represented for each state, and the weighted average coal properties. The largest West Virginia users of West Virginia coal are listed in Table 4.8-6 along with relevant plant information and coal properties.

Table 4.8-5. States Receiving West Virginia Coal Deliveries to Utility Plants in 1979

State	Quantity (10^3 Tons)	Percentage of Total Coal Used in State	Weighted Average		
			Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
West Virginia	23,648	86	2.06	13.8	3.41
Ohio	8,129	15	2.06	13.6	3.62
Michigan	4,542	19	2.53	10.9	4.01
Pennsylvania	4,387	11	2.54	12.0	4.10
North Carolina	3,161	15	0.84	13.6	1.40
New Jersey	1,286	59	2.11	10.1	3.29
New Hampshire	909	97	2.58	7.8	3.83
Maryland	764	15	0.88	10.8	1.40
Virginia	758	15	0.83	10.5	1.33
Kentucky	388	2	0.81	11.7	1.33
Alabama	243	1	1.79	12.8	2.90
New York	173	3	2.46	7.8	3.75
Remaining 7 States	332	< 1	1.93	12.8	3.24
TOTAL	48,722	–	2.03	13.0	3.34

Table 4.8-6. West Virginia Utility Plants Receiving West Virginia Coal Deliveries in 1979

Plant	Size (MW)	SO_2 Limit (lb/10^6 Btu)	Quantity (10^3 Tons)	Percentage of Total Coal Used by Plant	Weighted Average		
					Sulfur (Percent)	Ash (Percent)	SO_2 (lb/10^6 Btu)
Amos	2,900	1.6	6,889	99	0.80	13.4	1.36
Harrisian	1,920	5.1	2,937	90	2.75	8.9	4.22
Mitchell	1,460	7.5	2,836	87	3.52	14.1	5.89
Mount Storm	1,686	2.7	2,532	92	1.98	18.6	3.45
Kammer	615	6.8	1,993	100	4.31	14.1	7.24
Fort Martin	1,107	3.1	1,853	64	2.40	14.6	3.99
Kanawha River	421	1.6	999	100	0.74	15.9	1.29
Pleasants	626	1.2	1,066	90	2.94	12.2	4.72
Albright	289	3.2	948	100	1.61	12.9	2.66
Sporn	1,037	3.2	663	30	0.87	15.9	1.54
Remaining Plants	–	–	932	93	1.20	14.3	2.00
TOTAL	12,648	–	23,648	86	2.06	13.8	3.41

SECTION 4
REFERENCES

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Appendix A: Averaging Times and Coal Sulfur Variability

Emission limits may be enforced or set on a long-term average basis. Alternately, they may be set or enforced on a 3-hour, 24-hour, or similar short-term average basis. The amounts of coal available for compliance with various emission limits as derived in this report are applicable only to long-term averages for large boilers. If short-term emission limits are specified, one may use the data in this report by determining the mean (long-term average) coal sulfur content that corresponds to the emission limit (maximum expected short-term value).

The maximum expected short-term value is dependent upon the statistical properties of the coal, the boiler size, and the emission regulation. For example, a 25-MW(e) boiler that must meet an emission limit of a 4.0 lb $SO_2/10^6$ Btu (3-hour average) may require a compliance coal with a mean sulfur content of 2.0 lb $SO_2/10^6$ Btu if uncleaned or with a mean sulfur content of 2.8 lb $SO_2/10^6$ Btu if cleaned.

The variability in coal properties such as sulfur content results from differences in:

- The chemical composition and structure of coal-forming vegetal matter
- The chemical changes that occurred during accumulation and burial of the vegetal matter
- The amount and nature of sediments deposited during accumulation of coal-forming material
- The characteristics of the sedimentary rocks above and below the coal seam
- The subsequent geologic history of the deposit such as the permeation of groundwater and depth of burial

Because of the nature of coal formation, there is a certain structure (as opposed to complete randomness) in the properties of a coal deposit. For this reason, it is possible to draw lines of constant sulfur content (isolines) on the map of a coal mine or reserve. Superimposed on this structure will be a certain amount of randomness. Thus, if samples are taken from a certain deposit, the statistical treatment of this data must recognize both structural and random characteristics of the samples.

EPA is concerned with the control of SO_2 emissions from coal combustion. This is a time dependent phenomenon, a sequence of emissions over successive time increments. This sequence of emissions will depend upon coal and the manner in which it is mined, prepared, transported, and fired in the boiler. It will also depend upon the use of air pollution control devices such as fabric filters and flue gas desulfurization units.

Mining operations transform the spatial characteristics of coal into a time sequence of varying coal properties. Alternative mining approaches or schemes within the same deposit will provide different time sequences of potential sulfur emissions. These sequences will be subsequently modified by coal preparation, coal transportation, coal blending, and sulfur emission control operations.

Important parameters used in previous studies to evaluate the random nature of coal sulfur variability include the relative standard deviation (RSD), the coal lot size, and the emission averaging time. The RSD, or coefficient of variation is defined as the standard deviation divided by the mean value. The coal lot size is the weight of coal that each data point represents. The averaging time is the time period over which the emission limit is averaged.

The structural or autocorrelation properties of the coal sulfur content are useful in forecasting future data from past data. Small autocorrelations may indicate that the correlation between past and present values is small, so that past data provide little useful information in predicting future events. If the autocorrelation is large, it is essential to determine the time dependent effect of events through modeling to predict future trends. Once these trends have been forecast, the random properties of the data can be used to provide an estimated measure of their accuracy.

Previous studies have indicated that, in general:

- Coal sulfur variability decreases with increasing lot size.
- The variability of sulfur emissions decreases with increasing averaging times.
- It is more difficult for small boilers to comply with a specific emission limit with a fixed averaging time than for large boilers. Because of sulfur variability, the mean sulfur value of compliance coals for small boilers is lower than for large boilers.
- The autocorrelation structure of coal data must be used to predict accurately the expected emissions from a potential compliance coal.
- Coal cleaning reduces the coal sulfur variability.

Previous studies have not provided sufficient data to predict the autocorrelation characteristics. However, for the purpose of this study a simplified procedure can be used to estimate the quantities of coal available for a given emission standard. While this procedure is not rigorously correct from a statistical standpoint, it will allow us to arrive at an estimate that is more nearly correct than those obtained by ignoring the effects of sulfur variability.

Estimates of the relationship of RSD to coal lot size, boiler size, and emission averaging time are presented in Table A-1. The RSD values in this table, which are estimated from previous studies,[1, 2] decrease with coal sample size.

By assuming that the variations of the sulfur content in coal is normally distributed, the mean coal sulfur content needed to comply with a given emission limit can be estimated by the equation:

$$\text{Mean coal } SO_2 \text{ content} = SO_2 \text{ emission limit}/(1 + Z \cdot RSD)$$

where Z is the normal variate corresponding to a given confidence level (see Table A-2) and RSD is the appropriate value for a given boiler size, averaging time, and cleaning condition. Table A-3 presents computed values of the mean coal SO_2 content that are equivalent to selected emission limits for various RSD values and Z = 3.

Table A-1. Typical Coal Sulfur RSD Values Reported by EPA as a Function of Coal Sample Size

Coal Sample Size (tons)	Plant Size (MWe)	Averaging Period (days)	Coal Sulfur RSD	
			Uncleaned	Cleaned
33	25	1/8	0.24	0.15
264	25	1	0.21	0.12
600	500	1/8	0.19	0.11
4,800	500	1	0.16	0.08
7,920	25	30	0.15	0.08
33,600	500	7	0.12	0.05
96,360	25	365	0.08	0.03
144,000	500	30	0.07	0.03
1,752,000	500	365	0.02	0.01

Sources: Reference 1 for uncleaned coals; reference 2 for cleaned coals.

Table A-2. Example Normal Variates and Implications of Confidence Level on Expected SO_2 Violations

Confidence Level (%)	Z = Normal Variate (Number of Standard Deviations between Mean and Limit)	Number of Days per Year of Expected Violations
84.13	1.0	58
95.00	1.645	18
97.72	2.0	8
99.87	3.0	0.5

Table A-3. Mean Coal SO_2 Contents Equivalent to Selected Short-Term Emission Limits for Various Values of Coal Sulfur RSD (Z = 3)*

Sulfur RSD	Short-Term Emission Limit (lb $SO_2/10^6$ Btu)				
	0.6	1.2	2.0	3.0	4.0
0.01	0.58	1.17	1.94	2.91	3.89
0.02	0.57	1.13	1.89	2.83	3.77
0.03	0.55	1.10	1.83	2.75	3.67
0.05	0.52	1.04	1.74	2.61	3.48
0.07	0.50	0.99	1.65	2.48	3.31
0.08	0.48	0.97	1.61	2.42	3.23
0.11	0.45	0.90	1.50	2.26	3.01
0.12	0.44	0.88	1.47	2.21	2.94
0.15	0.41	0.83	1.38	2.07	2.76
0.16	0.41	0.81	1.35	2.03	2.70
0.19	0.38	0.76	1.27	1.91	2.55
0.21	0.37	0.74	1.23	1.84	2.45
0.24	0.35	0.70	1.16	1.74	2.33
0.30	0.32	0.63	1.05	1.58	2.11
0.33	0.30	0.60	1.00	1.50	2.00

* Z=3 represents a confidence level of 99.87%, or one expected 24-hour average violation in 769 days.

APPENDIX A REFERENCES

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